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भाग 1 पद्धति क — उच्च परिशुद्धता वाली द्रवणी भाप टरबाइनें

Indian Standard

RULES FOR STEAM TURBINE THERMAL ACCEPTANCE TESTS

PART 1 METHOD A — HIGH ACCURACY FOR LARGE CONDENSING STEAM TURBINES

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CONTENTS

INTRODUCTION 1

Clause

1. Scope and object 4
    - 1.1 Scope 4
    - 1.2 Object 4
    - 1.3 Matters to be considered in the contract 4
2. Units, symbols, terms and definitions 5
    - 2.1 General 5
    - 2.2 Symbols, units 5
    - 2.3 Subscripts, superscripts and definitions 6
    - 2.4 Definition of guarantee values and test result 9
3. Guiding principles 11
    - 3.1 Advance planning for test 11
    - 3.2 Preparatory agreements and arrangements for tests 12
    - 3.3 Planning of the tests 13
    - 3.4 Preparation of the tests 13
    - 3.5 Comparison measurements 17
    - 3.6 Setting for tests 17
    - 3.7 Preliminary tests 18
    - 3.8 Acceptance tests 18
    - 3.9 Repetition of acceptance tests 21
4. Measuring techniques and measuring instruments 21
    - 4.1 General 21
    - 4.2 Measurement of power 27
    - 4.3 Flow measurements 32
    - 4.4 Pressure measurements (excluding condensing turbine exhaust pressure) 42
    - 4.5 Condensing turbine exhaust pressure measurement 46
    - 4.6 Temperature measurement 49
    - 4.7 Steam quality measurement 52
    - 4.8 Time measurement 60
    - 4.9 Speed measurement 60
5. Evaluation of tests 60
    - 5.1 Preparation of evaluation 60
    - 5.2 Computation of results 61
6. Correction of test results and comparison with guarantee 62
    - 6.1 Guarantee values and guarantee conditions 62
    - 6.2 Correction of initial steam flow capacity 62
    - 6.3 Correction of maximum output 63
    - 6.4 Correction of thermal and thermodynamic efficiency 63
    - 6.5 Definition and application of correction values 64

6.6 Correction methods 65
6.7 Variables to be considered in the correction 67
6.8 Guarantee comparison 68

Appendix A — Feedwater heater leakage and condenser leakage test 71
Appendix B — Throat tap nozzle 72
Appendix C — The use of flow straighteners in fluid flow measurements 76

Indian Standard

RULES FOR STEAM TURBINE THERMAL ACCEPTANCE TESTS

PART 1 METHOD A — HIGH ACCURACY FOR LARGE CONDENSING STEAM TURBINES

NATIONAL FOREWORD

This Indian Standard which is identical with IEC Pub 953-1(1990), issued by the International Electrotechnical Commission, was adopted by the Bureau of Indian Standards on the recommendation of the Rotating Machinery Sectional Committee (ET 15) and approval of the Electrotechnical Division Council.

The text of IEC standard has been approved as suitable for publication as Indian Standard without deviations.

CROSS REFERENCES

In this adopted standard, reference appears to certain International Standards for which Indian Standards also exist. The corresponding Indian Standards which are to be substituted in their place are given below along with their degree of equivalence for the editions indicated:

International Standard	*Corresponding Indian Standard*	*Degree of Equivalence*
ISO 31-3 : 1992 Quantities and Units — Part : 3 Mechanics	IS 1890 (Part 3) : 1994 Quantities, units and symbols: Part 3 Mechanics (*first revision*)	Identical
IEC 953-2 : 1990 Rules for steam turbine thermal acceptance tests— Part 2 : Method B—Wide range of accuracy for various types and sizes of turbines	IS 14198 (Part 2) : 1994 Rules for steam turbine thermal acceptance test: Part 2 Method B — Wide range of accuracy for various types and sizes of turbines	Identical

The concerned technical committee has reviewed the provisions of ISO 5167-1 : 1991 referred to in this adopted standard and has decided that it is acceptable for use in conjunction with this standard.

Only the English language text given in the International Standard has been retained while adopting it as Indian Standard, and as such the page numbers given here are not the same as in IEC publication.

For the purpose of deciding whether a particular requirement of this standard is complied with, the final value, observed or calculated, expressing the results of a test, shall be rounded off in accordance with IS 2 : 1960 'Rules for rounding off numerical values (*revised*)'. The number of significant places retained in the rounded off value should be same as that of the specified value in this standard.

INTRODUCTION

The rapid development of measuring techniques, the increasing capacity of steam turbines and the introduction of nuclear power plants necessitated a revision of IEC Publication 46 (1962) regarding acceptance tests.

Since all the needs of the power industry in the different parts of the world could not be satisfied by one single publication, the complete standard is divided into two parts, describing two different approaches for conducting and evaluating thermal acceptance tests of steam turbines and which can be used separately:

a) Method A, which is Part 1 of the standard (IEC 953-1), deals with thermal acceptance tests with high accuracy for large condensing steam turbines.

b) Method B, which is Part 2 of the standard (IEC 953-2), deals with thermal acceptance tests with a wide range of accuracy for various types and sizes of steam turbines.

1) Basic philosophy and figures on uncertainty

Part 1 provides for very accurate testing of steam turbines to obtain the level of performance with minimum measuring uncertainty. The operating conditions during the test are stringent and compulsory.

Method A is based on the exclusive use of the most accurate calibrated instrumentation and the best measuring procedures currently available. The uncertainty of the test result is always sufficiently small that it normally need not be taken into acount in the comparison between test result and guarantee value. This uncertainty will not be larger than about 0.3% for a fossil fired unit and 0.4% for a nuclear unit.

The cost for instrumentation and the efforts for preparing and conducting the tests will generally be justified economically for large and/or prototype units.

Method B provides for acceptance tests of steam turbines of various types and capacities with appropriate measuring uncertainty. Instrumentation and measuring procedures have to be chosen accordingly from a scope specified in the standard which is centred mainly on standardized instrumentation and procedures, but may extend eventually up to very high accuracy provisions requiring calibration. The resulting measuring uncertainty of the test result is then determined by calculating methods presented in the standard and normally, if not stated otherwise in the contract, taken into account in the comparison between test result and guarantee value. The total cost of an acceptance test can therefore be maintained in relationship with the economic value of the guarantee values to be ascertained.

The specifications of the operating conditions during the test are somewhat more flexible in this method; furthermore, procedures are recommended for treating cases where these specifications cannot be met.

When good-standardized instrumentation and procedures are applied in a test, the measuring uncertainty of the result will usually amount to 0.9% to 1.2% for a large fossil fuel fired condensing unit, to 1.1% to 1.4% for a nuclear unit and to 1.5% to 2.5% for back pressure, extraction and small condensing turbines. It is possible to reduce these values by additional improvement in instrumentation, primarily by additional measurements of primary mass flows and/or calibration of measuring devices for primary mass flow.

2) Main difference between Methods A and B

In Method A, much more detailed information concerning the preparation and conduct of the tests and the measuring techniques are contained for guidance of the parties to the test than in Method B. In Method B, the detailed treatment of these objectives is left somewhat more to the discretion and decisions of the participants and necessitates sufficient experience and expertise on their part.

3) Guiding principles

The requirements concerning the preparation and conditions of the test and especially such conditions of the test as duration, deviations and constancy of test conditions and acceptable differences between double measurements are more stringent in Method A.

The test should be conducted preferably within eight weeks after the beginning of the operation. It is the intent during this period to minimize performance deterioration and risk of damage to the turbine.

Preliminary tests including enthalpy drop tests should be made during this period to monitor HP and IP turbine section performance. However, these tests do not provide LP section performance and for this reason it is imperative to conduct the acceptance tests as soon as practicable.

Whatever the case, when using Method A, if an enthalpy drop test indicates a possible deterioration of the HP or IP section, or if the plant conditions require that the tests be postponed more than four months after the initial start, then the acceptance tests should be delayed.

An adjustment of the heat rate test results to start-up enthalpy drop efficiencies or for the effects of aging is not permitted when using Method A.

If the test has to be postponed, Method A proposes that the test be carried out after the first major internal inspection; several methods are proposed for establishing the approximate condition of the turbine prior to the tests.

4) Instruments and methods of measurement

a) Measurement of electrical power

In addition to the conditions required for the measurement of electric power, which are similar in both methods, Method A requires a check of the instruments by a comparison measurement after each test run; the permissible difference between double measurements is limited to 0.15%.

b) Flow measurement

For the measurement of main flows the use of calibrated pressure difference devices is required in Method A. The application of a device not covered by international standardization, the throat-tap nozzle, is recommended therein and details of design and application are given.

The calibration of these devices shall be conducted with the upstream and downstream piping and flow-straightener. Methods for the necessary extrapolation of the discharge coefficient from the calibration values are given.

In Method B standardized pressure-difference devices are normally applied for flow measurement. Calibration is recommended where a reduction of overall measuring uncertainty is desirable. Double or multiple measurement of primary flow is recommended for the reduction of measuring uncertainty and a method for checking the compatibility is described.

c) Pressure measurement
The requirements and recommendations for pressure measurements are essentially similar. Only the methods for the measurement of exhaust-pressure of condensing turbines differ to some extent.

d) Temperature measurement
The requirements are essentially similar in both methods. However detail requirements are more stringent in Method A:

- calibration before and after the test,
- double measurement of the main temperature with 0.5 K maximum difference,
- thermocouples with continuous leads,
- required overall accuracy.

e) Steam quality measurements
Methods A and B are identical.

5) *Evaluation of tests*

The preparatory work for the evaluation and calculation of the test results is covered in a very similar manner in Methods A and B. However, quantitative requirements are more stringent in Method A.

Method B contains some proposals for handling cases where some requirements have not been met to avoid rejection of the test.

In addition, Method B contains detailed methods for calculation of measuring uncertainty values of measured variables and test results.

Method B recommends other methods for conducting and evaluating of the tests after the specified period and without a previous inspection.

6) *Correction of test results and comparison with guarantees*

The correction of test results to guarantee conditions is covered in both Methods A and B.

Method A provides for the comparison of test results to guarantee without consideration of measuring uncertainty.

Method B gives a broader spectrum of correction procedures. Furthermore, the measuring uncertainty of the result is taken into account in the guarantee comparison.

7) *Proposals for application*

Since the acceptance test method to be applied has to be considered in the details of the plant design, it should be stated as early as possible, preferably in the turbine contract, which method will be used.

Method B can be applied to steam turbines of any type and any power. The desired measuring uncertainty should be decided upon sufficiently early, so that the necessary provisions can be included in the plant.

If the guarantee includes the complete power plant or large parts thereof, the relevant parts of either method can be applied for an acceptance test in accordance with the definition of the guarantee value.

1. Scope and object

1.1 *Scope*

The rules given in this standard are applicable primarily to thermal acceptance tests with high accuracy for condensing steam turbines driving generators for electric power services. Some of the provisions of these rules are relevant to turbines for applications other than driving electric power generators.

These rules provide for the testing of turbines operating with either superheated or saturated steam. They include measurements and procedures required to determine specific enthalpy within the moisture region and describe precautions necessary to permit testing while respecting radiological safety rules in nuclear plants.

These rules contain information also applicable to the testing of back-pressure turbines, extraction turbines and mixed-pressure turbines. Only the relevant portion of the rules need apply to any individual case.

Uniform rules for the preparation, carrying out and evaluation of the acceptance tests are defined in this standard. Details of the conditions under which the acceptance tests shall take place are included.

Should any complex or special case arise not covered by these rules, appropriate agreement shall be reached by manufacturer and purchaser before the contract is signed.

1.2 *Object*

The purpose of the thermal acceptance tests of steam turbines and turbine plants described in this standard is to verify any guarantees given by the manufacturer of the plant concerning:

a) turbine plant thermal efficiency or heat rate;

b) turbine thermodynamic efficiency or steam rate or power output at specified steam flow conditions;

c) main steam flow capacity and/or maximum power output.

The guarantees with their provisions shall be formulated completely and without contradictions (see 2.4). The acceptance tests may also include such measurements as are necessary for corrections according to the conditions of the guarantee and checking of the results.

1.3 *Matters to be considered in the contract*

Some matters in these rules have to be considered at an early stage. Such matters are dealt with in the following sub-clauses:

Sub-clause	
1.1	(paragraph 4)
1.2	(paragraph 2)
3.1	(paragraphs 3 and 4)
3.3.3	(paragraph 1)
6.6	
6.8	

2. Units, symbols, terms and definitions

2.1 *General*

The International System of Units (SI) is used in these rules; all conversion factors can therefore be avoided.

The coherent units for all relevant quantities are given in the Table in 2.2. Some conversion factors are given as well for specific heat rates based on units other than W/W.

2.2 *Symbols, units*

For the purpose of these rules the following symbols, definitions and units shall be used:

Grandeurs	Symboles	Unités	Exemples de multiples et sous-multiples	Autres unités ISO
Puissance	P	W	kW	
Débit masse	$\dot{m}$	kg/s		
Pression absolue	p_{abs}	Pa	kPa	bar[1]
Pression manométrique	p_e	Pa	kPa	bar[1]
Pression ambiante (barométrique)	p_{amb}	Pa	kPa	bar[1] mbar
Différence de pression	Δp	Pa	kPa	
Température thermodynamique	T, Θ	K		
Température Celsius	t, ϑ			°C
Ecart de température	Δt	K		
Distance verticale	H	m	mm	
Enthalpie massique	h	J/kg	kJ/kg	
Chute d'enthalpie massique	Δh	J/kg	kJ/kg	
Chaleur massique	c	J/kg · K	kJ/kg · K	
Titre (masse de vapeur saturée sèche par unité de masse de vapeur humide)	x	kg/kg	g/g	
Vitesse de rotation	n	s^{-1}		min^{-1}
Vitesse linéaire	v	m/s		
Masse volumique	ϱ	kg/m^3		
Volume massique	v	m^3/kg		
Diamètre	D	m	mm	
Accélération de la pesanteur	g	m/s^2		
Rendement thermique	η_t	W/W	kW/kW	
Rendement thermodynamique	η_{td}	W/W	kW/kW	
Consommation spécifique de chaleur	HR	W/W	kW/kW	kJ/kW · s, kJ/kW · h
Consommation spécifique de vapeur	SR	kg/W · s ou kg/J	kg/kW · s kg/kJ	kg/kW · h
Débit de chaleur	$\dot{Q}$	J/s	kJ/s	
Facteur de cavitation	K	1		
Concentration	C	Selon nature du traceur		
Facteur de correction selon 6.6*a)*	F	1		
Facteur de correction selon 6.6*b)*	F^*	1		
Exposant isentropique	κ	—		
Coefficient de décharge	C_d	—		
Coefficient de débit	α	—		

---

[1] Admitted by CIPM and ISO for temporary use with fluids only.

Relation between Heat Rate and Thermal Efficiency:

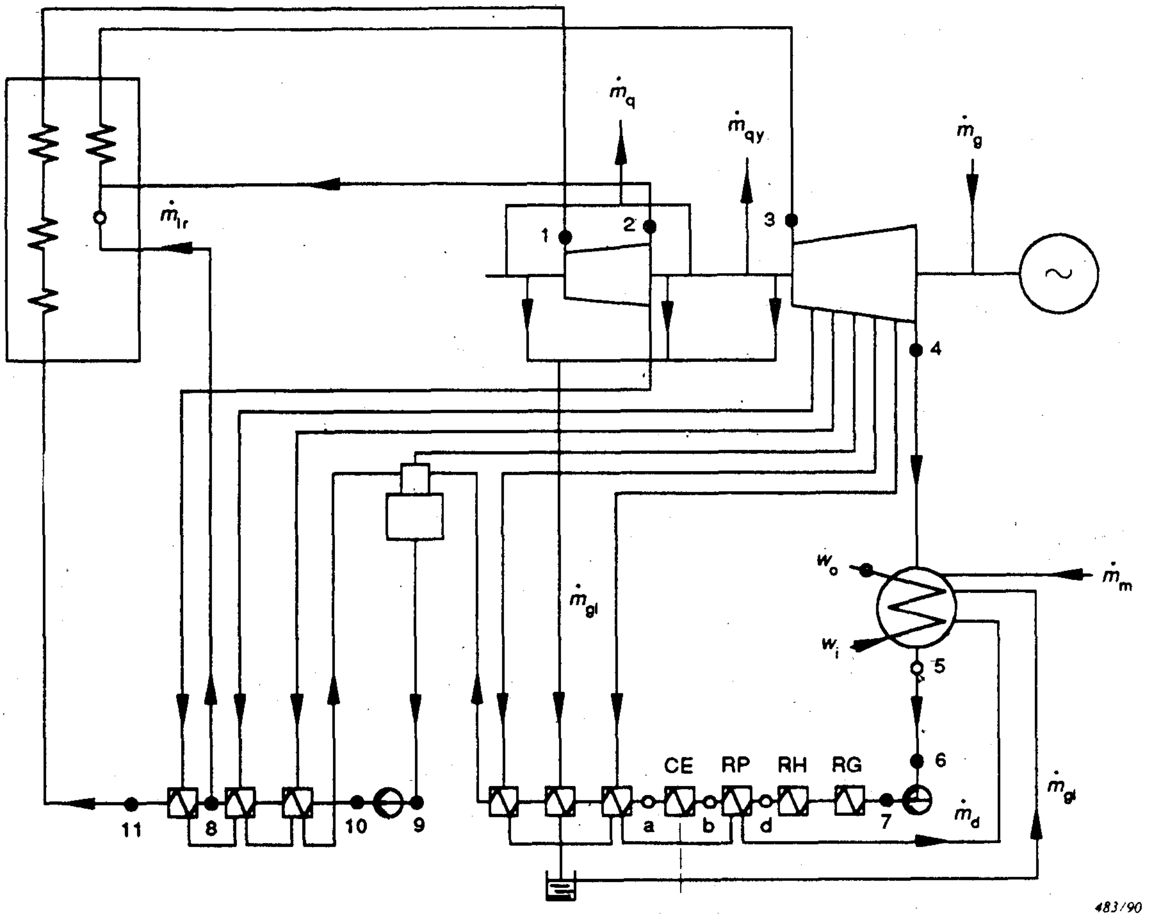
Units used for HR	*Relationship*
W/W, kW/kW, kJ/kW · s	$HR = \frac{1}{\eta_t}$
kJ/kW · h	$HR = \frac{3\,600}{\eta_t}$
kJ/MW · s	$HR = \frac{1\,000}{\eta_t}$
kcal/kW · h	$HR = \frac{859.845}{\eta_t}$
BTU/kW · h	$HR = \frac{3412.14}{\eta_t}$

2.3 *Subscripts, superscripts and definitions*

Quantity	Subscript	Position or definition
Power	b	At generator terminals
	a	Taken by auxiliaries not driven by the turbine (see 4.2.3); (see also IEC 34)
	g	Net power output: $P_g = P_b - P_a$
	c	At turbine coupling, less power required by turbine auxiliaries, if driven separately (see 4.2.3)
	i	Internal to the turbine
	mech	Mechanical losses of pump and pump drive
Initial steam flow rate and output	max	Values for fully opened control valves
Steam condition and flow rate	1	Directly upstream of high pressure (HP) turbine stop valve(s) and the steam strainer(s) (if any) that are included in the turbine contract
	2	At exhaust of the turbine HP from which steam passes to the reheater
	3	Directly upstream of intermediate pressure (IP) turbine stop valves
	4	At exhaust of the turbine(s) discharging to the condenser
Condensate and feed water conditions and flow rates	5	At condenser discharge
	6	At inlet to condensate pump
	7	At discharge from condensate pump
	8	See figure 1a
	9	At inlet of boiler feed pump
	10	At outlet of boiler feed pump
	11	At outlet of final feed heater
	b	After passage through the condensate pump and any coolers (oil, generator, gas/air) included in the contract
	d	At outlet from the drain cooler
	a	At outlet of air ejector condenser
	is	Refers to water taken from the feed-water system to the superheater for regulation of the initial steam temperature
	ir	Refers to water taken from the feed-water system to the reheater for control of the reheated steam temperature

Quantity	Subscript	Position or definition
Make up water conditions and flow rate	m	Measurements adjacent to the inlet flange of the condensate system or of the evaporator
Gland steam conditions and flow rates	g	Steam supplied to glands from a separate source
	gl	Leak-off steam from glands and valve stems returned to the system and included in the initial steam flow
	q	Flow of leak-off steam from glands and valve stems at inlet end or before a reheater which is led away for any extraneous purpose and neither it nor its heat is delivered to any part of the turbine cycle
	qy	Leak-off flows similar to q, but coming from a point or points downstream of a reheater
Main steam flow rate and concentration	M	Main steam flow at outlet of reactor
Mass flow rate and concentration	F	Refers to feed-water for reactor
	core	Refers to medium fluid passing through reactor core
	cond	Refers to condensed steam
Mass flow rate and concentration	inj	Refers to injected tracer solution
	E	At entry into core of PWR
	R	Recirculated water flow from water separator
Condenser cooling water	w	
	wi	Condenser inlet
	wo	Condenser outlet
	wio	Average value between condenser inlet and outlet
Efficiency	t	Thermal
	td	Thermodynamic
Enthalpy drop	s	Refers to isentropic enthalpy drop
Velocity	throat	At throat of flow-metering nozzle
Static pressure	sat	Saturation pressure of water at pertinent temperature
Concentration	wat	In water phase
	L	In pump loop of BWR
	B	In blow-down water of PWR
	inj	Of injected tracer
	O	At injection point before tracer injection
Test results and guaranteed values	g	Guaranteed
	c	Corrected
	m	Measured
Correction factor F or F*	tot	Product of all individual correction factors
	1, 2, 3	Numbering of individual correction factors
	η	For correction of efficiency
	P	For correction of output
General use	i, j	Numbering subscripts

Quantity	Superscript	Definition
Efficiency	/	Reference value of computer-calculated efficiency
General	—	Average value



GC: Generator gas cooler
OC: Oil cooler
DC: Drain cooler
EC: Air ejector condenser

The point number remains the same for the same item of any other turbine type: for example, Point 9 will be at the inlet of the feed pump, Point 8 may be anywhere between Points 6 and 11.

FIG. 1a. — Reheating regenerative condensing turbine with feed-water heating.

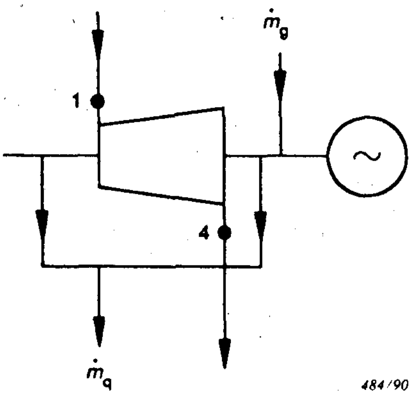


FIG. 1b. — Straight condensing or back-pressure turbine without feed-heating.

FIG. 1. — Diagram for interpretation of symbols and subscripts.

2.4 *Definition of guarantee values and test results*

For the quantitative description of the thermodynamic performance of a steam turbine or steam turbine plant, several quantities are technically appropriate and generally applied. Guaranteed values are expressed as such quantities and, consequently, test results are to be evaluated in the same manner.

The general definition of these quantities is always quite obvious. The details, however, may be different in each case and shall be fully considered (see also 1.2).

2.4.1 *Thermal efficiency*

For a power station turbine with regenerative feed heating, the thermal efficiency is the significant criterion. It is defined as the ratio of power output to heat added to the cycle from external sources.

$$\eta_t = \frac{P}{\Sigma\,(\dot{m}_j\,\Delta\,h_j)} \qquad (1)$$

where:

$\dot{m}_j$ are the mass flows, to which heat is added

Δh_j the resulting enthalpy rises

For each specific case a guarantee heat cycle together with the guarantee terminal parameters has to be defined as a basis for guarantee definition and test evaluation. It should be as simple as possible and as near as practicable to the cycle configuration to be realized for the test (see also 3.4.4).

A practical definition for a turbine plant with single reheat and feed heating according to figure 1a is then:

$$\eta_t = \frac{P_b\,(\text{or } P_g \text{ or } P_c)^*}{\dot{m}_1\,(h_1 - h_{11}) + \dot{m}_3\,(h_3 - h_2)} \qquad (2)$$

Any additional heat and/or mass flow added to or subtracted from the cycle for example by make-up flow $\dot{m}_m$, spray attemperator flow $\dot{m}_{ir}$ or $\dot{m}_{is}$ or additional extraction for steam air preheater has to be accounted for in the evaluation by an appropriate correction of the test result (see Clause 6). Losses are not included in this definition, but treated according to 5.2.3.4.

To keep the sum of corrections small, it may be reasonable to include in the guarantee definition, by means of additional terms, important heat and mass flows, present in the cycle configuration for the test for technical reasons (e.g. spray attemperator, reactor blow down, etc.).

This, however, also modifies the thermodynamic character of the definition and the resulting values of the thermal efficiency are not directly comparable with those according to formula (2). Furthermore, the correction procedure will not be avoided altogether in this way, because it is improbable that the values of these additional flows during the test coincide exactly with those in the amended guarantee definition.

It is impracticable to describe in these rules all the possible variations in turbine cycles. In cases of complicated deviations of test cycle configuration from guarantee definition it is advisable to use the correction procedure according to 6.6.1.

---

* According to contract specification.

2.4.2 *Heat rate*

The heat rate traditionally has been used (and is still used) for the same objective as thermal efficiency, which is applied in these rules.

In a coherent unit system (SI):

$$HR = \frac{1}{\eta_t} \qquad (3)$$

The unit of the so calculated heat rate is kW/kW = kJ/kW · s

Heat rate values expressed in other units can be converted easily to thermal efficiency values, taking into account the appropriate conversion factors (see 2.2).

2.4.3 *Thermodynamic efficiency*

For a turbine receiving all the steam at one initial steam condition and discharging all the steam at a lower pressure (condensing or back-pressure turbine without regenerating feed-heating or reheat) the thermodynamic efficiency is the most appropriate measure of performance. It is defined as the ratio of power output to isentropic power capacity (product of steam mass flow and isentropic enthalpy drop between initial steam condition and exhaust pressure).

$$\eta_{td} = \frac{P}{\dot{m}\,\Delta h_s} \qquad (4)$$

The numerical value of thermodynamic efficiency does not depend on the initial steam and exhaust conditions, but is the indication for the efficiency of the expansion only.

The formula defining the thermodynamic efficiency for a straight condensing turbine without feed-heating according to Figure 1b is then:

$$\eta_{td} = \frac{P_b \,(\text{or } P_g \text{ or } P_c)\,^*}{\dot{m}_1 \cdot \Delta h_{s\,1,4}} \qquad (5)$$

where:

$\Delta h_{s\,1,4}$ is the isentropic enthalpy drop between initial steam condition at point 1 and pressure at point 4.

2.4.4 *Steam rate*

The steam rate traditionally has been used (and is still used) as a performance criterion for turbines as described in 2.4.3. It is defined as the ratio of initial steam flow rate to power output and is connected with thermodynamic efficiency as follows in coherent units (SI):

$$SR = \frac{\dot{m}}{P} = \frac{1}{\eta_{td} \cdot \Delta h_s} \qquad (6)$$

Steam rate values expressed in other units can be converted to thermodynamic efficiency values after determination of the relevant Δh_s value, taking into account the appropriate conversion factors (see 2.2).

---

* According to contract specification.

Since numerical steam rate values depend also on initial steam and exhaust conditions, they are not comparable for turbines with different specified conditions. Therefore, thermodynamic efficiency is used in these rules.

2.4.5 *Main steam flow capacity*

The maximum flow rate of main steam with all regulating valves wide open under specified steam conditions (usually the steam conditions according to the definition of the other guarantee values) is a measure of the maximum flow capacity of the turbine.

2.4.6 *Maximum power output*

The power output of the turbine at the maximum flow rate of main steam can be guaranteed for a specified guarantee heat-cycle, which may differ to some extent from the guarantee heat cycle valid for the thermal efficiency.

3. Guiding principles

3.1 *Advance planning for test*

The parties to any test under these rules shall reach agreement as to the testing procedure, the interpretation of guarantees, the number, location, and arrangement of measuring points and measuring devices, valves and piping arrangements at the time of design of the turbine plant and of the piping. This especially applies to steam turbines in nuclear power stations where subsequent modifications are often impracticable and the measuring points are not always accessible once the plant has started to operate. It is recommended that, for the most important measurements, special connection facilities such as flanges and thermometer wells be provided for the measuring equipment so that the acceptance tests can be carried out without impairing the instruments for normal operation.

The instrumentation has to be selected in such a way that power and heat flows which enter and leave the "system", as defined in the contract, and the conditions at its boundaries can be determined.

All necessary preparations and precautions have to be taken to meet the specifications of these rules regarding measuring accuracy.

The following is a list of typical items upon which agreement should be reached during the plant design:

a) Location of, and piping arrangement around flow measuring devices on which test calculations are to be based.

b) Number and location of valves required to ensure that no unaccounted for flow enters or leaves the test cycle, or bypasses any cycle component. In a nuclear plant there may be some make-up line or emergency valving that cannot be blocked and for which accounting must be made.

c) Number and location of temperature wells and pressure connections required to ensure correct measurements at critical points.

d) Number and location of duplicate instrument connections required to ensure correct measurements at critical points.

e) Handling of leak-off flows to avoid complications in testing or the introduction of errors.

f) Means of measuring pump shaft leakages.

g) Method of determining steam quality including sampling technique as required. The recommended methods are given in 4.7.

Specification, installation, precision class and calibration of the normal station instrument transformers shall be chosen suitably if it is intended to use them for the acceptance test (see also 4.2.7).

3.2 *Preparatory agreements and arrangements for tests*

a) Before the test, the parties to the tests shall reach an agreement as to the test programme, the specific objectives of the tests, the measuring methods and the method of operation with due regard to a limitation of the necessary corrections, the method for correcting the test results and for guarantee comparison with due regard to the contract conditions.

b) Agreement shall be reached as to the variables to be measured, the measuring instruments and who is to supply them, the location of the indicating instruments and the operating and recording personnel required.

c) Agreement shall be reached on the methods of obtaining the comparison measurement (see 3.5).

d) Agreement shall be reached on such matters as the means of securing constancy of steam conditions and output.

e) Instruments liable to failure or breakage in service should be duplicated by reserve instruments, properly calibrated, which can be put into service without delay. A record of such change of instrument during a test shall be clearly made on the observer's record sheet.

Instruments shall be located and arranged so that they may be read accurately with comfort by the observer. The calibration environment should be as close as practicable to the environment in which the instrument will operate during the test. This may be accomplished by locating the instruments in a controlled environment.

f) The determination of the enthalpy of steam superheated less than 15 K, or of the quality of steam containing moisture, may be made only when the parties agree upon the method to be employed for this determination. The agreement, the method for making the determination and the method of applying the enthalpy or quality values to the test results shall be fully described in the test report.

The rate of flow of steam of any quality may be determined, where practicable, by condensing it completely and then measuring the condensate flow.

g) Agreement shall be reached as to the method of calibration of instruments, by whom and when.

h) For any of the measurements necessary for a test under these rules, any methods may be employed other than those prescribed in these rules, provided they are mutually agreed upon in writing before the test by the parties to the test. Any such departure from the prescribed methods shall be clearly described in the test report. In the absence of written agreements, the rules herein shall be mandatory.

i) An independent expert may be a party to all agreements.

j) Agreement shall be reached on the minimum number of operating and recording personnel that is required.

3.3 *Planning of the tests*

3.3.1 *Time for acceptance tests*

Unless otherwise provided in the contract, acceptance tests on site should be planned to take place if practicable within eight weeks* after the first synchronization, or immediately following an inspection outage, provided any deficiencies affecting performance have been corrected. In any event, except with written agreement to the contrary, the acceptance test shall take place within the guarantee period specified in the contract.

3.3.2 *Direction of acceptance tests*

The responsibility for the direction of the acceptance tests shall be clearly assigned by the parties prior to the test, preferably to one person. This person is responsible for the correct execution and evaluation of the acceptance tests, and serves as arbitrator in the event of disputes as to the accuracy of observations, conditions, or methods of operation. He is entitled and obliged to obtain information on all necessary details.

Accredited representatives of the purchaser and the manufacturer may at all times be present to verify that the tests are conducted in accordance with these rules and the agreements made prior to the tests.

A party to the contract who is not responsible for the direction of the acceptance tests shall also be given the opportunity of obtaining information a sufficient time before the tests.

3.3.3 *Cost of acceptance tests*

The contract shall stipulate who is to bear the costs of acceptance tests and any repeated acceptance tests (see also 3.5, 3.7 and 3.9).

3.4 *Preparation of the tests*

3.4.1 *Condition of the plant*

Prior to commencement of the acceptance tests, it is essential to be satisfied that the steam turbine and driven machine are in suitable condition, together with the condenser and/or feedheaters if included in the guarantee. It is also essential to verify that leaks in the condenser, feedheaters, pipes and valves have been eliminated.

Prior to the acceptance tests, the supplier shall be given the opportunity to check the condition of the plant, if necessary by making his own measurements. Any deficiency determined at this time shall be rectified.

Although these rules deal specifically with the performance testing of steam turbine generators, it is required that all other equipment supplied as part of the same turbine generator contract shall be in full and correct working order and in normal commercial disposition during the turbine generator tests. This requirement does not apply if other equipment has been ordered as an extra to the contract after the performance guarantees have been contractually agreed, or if special measures to render the equipment non-operative during the tests have been agreed beforehand between the parties to the test and are described in prominent detail in the test report. An example of equipment in this category would be piping and valves, supplied as part of the same turbine generator contract, designed to permit steam to by-pass part or all of the turbine expansion stages for temperature-matching purposes during start-up.

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* It is the intention, during this period, to minimize performance deterioration and risk of damage to the turbine. Enthalpy drop tests or preliminary tests should be made during this period to monitor HP and IP turbine section performance. However, these tests do not provide LP section performance and for this reason it is imperative to conduct the acceptance test as soon as practicable.

In any event, if either the enthalpy drop test shows undue deterioration to the HP or LP section, or if plant conditions delay the tests for more than four months after initial operation, the acceptance test should be postponed.

Adjusting of heat rate test results to startup enthalpy drop efficiencies or for the effects of ageing is not permitted.

3.4.2 *Condition of the steam turbine*

The condition of the steam turbine can be determined by an internal inspection of the steam path generally by opening the steam turbine or by comparison measurements according to 3.5.

Opening the turbine or an individual casing in order to locate a defect may be taken into consideration if large and inexplicable deviations are apparent from the comparison measurements.

3.4.3 *Condition of the condenser*

When the guarantees include the condenser performance and are based upon cooling water flow and temperature, the condenser shall be clean and the system shall be tested for sufficient air tightness. Agreement of the two parties to these matters shall be reached.

The condition of the condenser shall be checked by opening the water boxes or measuring the terminal temperature difference. In the case of deposits* the condenser shall be cleaned by the purchaser prior to the acceptance tests at the request of the supplier, or the parties concerned by the test may agree on a suitable correction.

3.4.4 *Isolation of the cycle*

The accuracy of the test results depends on the isolation of the system. Extraneous flows should be isolated from the system and internal flows which bypass in an unaccounted-for way either cycle components or mass-flow measuring equipment should be eliminated, if practicable, to obviate the need for measurement. If there is any doubt about the ability to isolate these flows during the test, preparations shall be made prior to the test to measure them.

All unused connections shall be blanked-off. If this is not practicable the connections shall be broken at a suitable point so that the outlets are under constant observation.

The equipment and flows to be isolated and the methods to accomplish this should be agreed well ahead of the initial operation date of the turbine. The isolation of the cycle has to be described in the test report.

When the system is properly isolated for a performance test, the unaccounted-for leakage resulting in unaccounted-for losses in storage volumes should be less than approximately 0.1% of the initial steam flow at full load. Excessive unaccounted-for leakages shall be eliminated before continuing the test. Water storage in the condenser hot well, deaerating and other extraction feedwater heaters, boiler drum(s), moisture separators, reheaters, and any other storage points within the cycle are to be taken into account (see also 5.2.3.4).

3.4.4.1 *Isolation of equipment and flow*

The following list includes items of the equipment and extraneous flows that shall be isolated from the primary turbine feedwater cycle:

a) Large-capacity storage tanks.

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* Deposits: salts or metal on the steam side and slime, ashes, bacteria, algae, etc., on the cooling water side.

b) Evaporators and allied equipment such as evaporator condenser and evaporator preheaters.

c) Bypass systems and auxiliary steam lines for starting, compatible with safe operation.

d) Bypass lines for condensate primary-flow-measuring devices.

e) Turbine sprays.

f) Drain lines on stop, intercept and control valves.

g) Interconnecting lines to other units.

h) Demineralizing equipment.

Isolation of demineralizing equipment does not necessarily mean removing the equipment from the cycle. It does, however, mean that all ties with other units shall be isolated and such equipment as recirculating lines that affect the primary flow measurement shall be isolated or the flows measured.

i) Chemical-feed equipment using condensate.

j) Boiler vents.

k) Steam-operated soot blowers.

l) Condensate and feedwater flow bypassing heaters.

m) Heater drain bypasses.

n) Heater shell drains.

o) Heater water-box vents.

p) Hogging jets.

q) Condenser water-box priming jets.

r) Steam or water for station heating.

s) Blow down from steam generator.

3.4.4.2 *Flows which shall be determined if not isolated*

The following extraneous flows which enter or leave the cycle in such a manner as to cause an error in the flows through the turbine shall be isolated from the system or measured:

a) Boiler fire door cooling flow and boiler-slag-tap-cooling coil flow.

b) Sealing and gland cooling flow on the following (both supply and return):

1) condensate pumps;
2) boiler feed pumps;
3) boiler-water or reactor circulating pump;
4) heater drain pumps when not self-sealed;

5) turbines for turbine-drive pumps;
6) control rod seals on nuclear reactors.

c) Desuperheating water.

d) Boiler feed pump minimum-flow lines and balance drum flow.

e) Steam for fuel oil atomization and heating.

f) Boiler blowdowns.

g) Boiler fill lines.

h) Turbine water-seal flow.

i) Desuperheating water for turbine cooling steam.

j) Emergency blowdown valve of turbine gland leakage and sealing system.

k) Turbine water-seal overflows.

l) Steam and water lines installed for washing the turbine.

m) Steam, other than gland leak-off steam, to the steam-seal regulating valve.

n) Make-up water, if necessary.

o) Pegging steam (such as higher stage extraction at light loads) for low-pressure operation of deaerator.

p) Heater vents shall be closed if practicable. If not, they shall be throttled to a minimum.

q) Deaerator overflow line.

r) Water leakage into any water-sealed flanges, such as water-sealed vacuum breakers.

s) Pump seal leakage leaving the cycle.

t) Automatic extraction steam for industrial uses.

u) Steam to air preheaters (if isolation is not practicable).

v) Water and steam sampling equipment. If it is impracticable to isolate water and steam sampling equipment, and if the sampling flow is significant, it shall be measured.

w) Deaerator vents.

x) Reactor-core spray.

y) Sub-cooled water used for moisture separator or reheater coil drain cooling.

z) Continuous drains from wet steam turbine casings and connection lines (if not included in the guarantee).

3.4.4.3 *Suggested methods and/or devices for isolating equipment from turbine feedwater cycle*

The following methods are suggested for isolating miscellaneous equipment and extraneous flows from the primary turbine feedwater cycle and for checking such isolation:

a) Double valves and tell-tales.

b) Blank flanges.

c) Blank between two flanges.

d) Removal of spool piece for visual inspection.

e) Visual inspection for steam blowing to atmosphere such as safety valves.

f) Closed valve which is known to be leak-proof (test witnessed by both parties) and not operated prior to or during the test.

g) Temperature indication (only acceptable under certain conditions — mutual agreement necessary).

h) Accurate measurements of levels in any tanks which should be isolated from the system.

i) Very important isolating valves (for example, HP and LP bypass valves) should be inspected and, if necessary, sealed prior to the test.

3.4.5 *Checks for leakage of condenser and feedwater heaters*

Condensers and feedwater heaters shall be checked for leakage and steps shall be taken to eliminate any significant leakage (see Appendix A).

In case of doubt the check can be repeated after the test.

3.4.6 *Cleanliness of the steam strainers*

If necessary, the steam strainers shall be cleaned before the acceptance tests.

3.4.7 *Checking of the test measuring equipment*

All measuring equipment shall be examined before the test as to its condition and suitability. It shall be further established whether the measuring instrument, the point of installation, and the installation are in accordance with relevant requirements. The results of all those checks shall be recorded in the test report.

3.5 *Comparison measurements*

For various reasons extraneous to the turbine generator it may not be practicable to conduct full-scale performance tests within the time limit specified in 3.3.1. In such circumstances, the following data, in well defined conditions of pressure, temperature, initial steam quality for wet steam units etc., should be recorded from the earliest practicable date:

a) turbine stage pressures;

b) turbine stage temperatures;

c) power output;

d) opening of governing valves;

e) enthalpy drop efficiency if steam is superheated;

f) Willans line, i.e. graph of steam flow/power output;

g) flow of leak-off steam from glands, etc.

The same readings taken in the same conditions just before the test and compared with the original readings will enable any significant changes in the conditions of the turbine to be determined.

The parties interested in the tests shall agree on the action to be taken in consequence of deterioration. In some circumstances, it may be appropriate that the test should be conducted immediately after the first major inspection provided that any deficiencies in the turbine generator unit affecting performance have been corrected during the inspection period.

3.6 *Settings for tests*

3.6.1 *Load settings*

The guarantee may be given and the tests carried out either on the basis of specific valve opening or a specific power output*. In planning the programme, it should be remembered that:

a) Tests at "valve point" positions tend to result in the best performance.

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* For nuclear power stations, the tests are carried out based on the guaranteed thermal output of the reactor.

b) "Valve point" loads and flows will probably not occur at the exact values expected by the manufacturer.

c) Test points should be chosen such that the manufacturer may have the opportunity to demonstrate and the purchaser may have the opportunity to know what the performance is in relation to that guaranteed.

When the tests are carried out at specific valve opening it shall be permissible, in order to obtain the most economical load, to adjust the load to within ±5% of the load specified for the guarantee.

As it might be difficult to set the load for a partial valve opening test exactly at the appropriate value, it shall be permissible to run two or more tests to straddle the load and obtain by interpolation the actual test result at the load adjusted in accordance with this clause.

In the event of variable pressure operation of a full arc admission turbine, tests shall be conducted with control valves wide open. The same applies to throttle control if the guarantee is based upon wide open control valves.

Manually operated nozzle or bypass valves, if provided, shall be in the position contemplated by the guarantee. If the contract or specification is not clear in this respect, the parties shall come to an agreement.

3.6.2 *Special settings*

No special adjustments shall be made to the turbine, for test purposes that are inappropriate for commercial and continuous operation under any and all of the specified outputs and operating conditions. Exceptions are air bleed adjustments to control the vacuum, the use of load-limiting devices or other similar test control means, such as isolation of the cycle to prevent extraneous flows and/or internal by-pass flows of steam or water by closing certain drains or other valves. These shall be consistent with the terms of the guarantee and practicable with regard to operating safety and technique.

The turbine shaft seals shall be adjusted to normal operating conditions before a test and arrangements made to measure outward or inward flow that will influence test results.

3.7 *Preliminary tests*

Preliminary tests may be run for the purpose of:

a) determining whether the turbine is in a suitable condition for the conduct of an acceptance test,

b) checking all instruments,

c) training personnel in test procedures.

After a preliminary test has been made, it may be considered, if mutually agreed, as an acceptance test.

If the preliminary tests are unsatisfactory, the causes shall be investigated and, if necessary, the turbine shall be placed at the disposal of the manufacturer so that the latter may examine it and ascertain whether it is in a suitable condition for an acceptance test.

3.8 *Acceptance tests*

3.8.1 *Constancy of test conditions*

All tests shall be preceded by a period temperature and flow stabilization, the duration of which shall be agreed upon by the parties interested in the test, since it will vary with the size of the turbine, the internal conditions, and the amount of load-change.

Any condition, the variation of which may influence the results of the test, shall be caused to become as nearly constant as practicable before the test begins, and shall be so maintained throughout the test, within the permissible variations according to 3.8.2.

In order to maintain constancy of throttling, the travel of the governing valve, in the opening direction only, should be limited to the chosen position and the governor should be sufficiently overwound to ensure that it does not respond to normal changes in system frequency.

3.8.2 *Maximum deviation and fluctuation in test conditions*

Except upon agreement to the contrary by the parties, the maximum permissible deviation of the average test conditions for each variable from that specified and the maximum permissible fluctuation of the variable during any one test run, shall not exceed the limit prescribed in Table I.

In general, it is more desirable to conduct the test as soon after first synchronization as practicable (see 3.3.1), even if the conditions in Table I cannot be met. In this instance, the correction curves shall be applicable for the test conditions.

3.8.3 *Duration of test runs and frequency of readings*

The requisite test duration is dependent on the steadiness of operating conditions and the speed of acquisition of test data. Accurately measurable changes in the level of water stored in the system may be a limiting factor.

The recommended duration of an acceptance test run is 2h. This may be reduced by agreement, but should be not less than 1 h.

During this period, readings of differential pressure flow-meters measuring primary flow should normally be taken every half minute. Readings of electrical power output, if based on indicating wattmeters in the absence of integrating meters (see 4.2.6) should be taken at intervals of not more than one min. Readings of primary pressures and temperatures should be taken at intervals of not more than 5 min. Fluctuating conditions necessitate shorter intervals between readings, especially of flowmeters, or a longer test duration in order to achieve a representative average (see 4.3.5). The duration of the capacity test should be chosen accordingly.

The time of the reading should be indicated to the observers through signals from a main clock. It may alternatively be taken from the observers' watches, which shall be synchronized with each other prior to each test run.

TABLE I

Maximum deviation and fluctuation in operating conditions

Variable	Max. permissible deviation of the average of the test from that specified	Max. permissible rapid fluctuation from the average during any one test run (see Note 1)
Initial steam pressure	±3% of absolute pressure (see Note 2)	±0.5% of absolute pressure
Initial and reheat steam temperature	Superheat $\leqslant 25$ K ± 8 K Superheat > 25 K ±15 K	±2 K ±1 K
Primary flow	Not specified	See 4.3.5
Dryness fraction at inlet for turbines supplied with wet steam	±0.005	±0.001
Exhaust pressure (condensing turbine)	±2.5% of absolute pressure (see Note 5)	±5%
Feed water temperature	±8 K (see note 3)	—
Extraction pressure	See note 4	—
Power	±5%	±0.25%
Voltage	±5%	—
Power factor	May vary between unity and specified value minus 0.05	—
When the condenser is included in the guarantee		
Cooling water inlet temperature	±5 K	±1 K
Cooling water flow	±10%	—
Air inlet temperature (for air-cooled condensers)	±10 K	±2 K

Notes 1. — A rapid fluctuation is one whose frequency is greater than twice the frequency of the reading.

2. — In any event the manufacturer's allowable variations in pressure and temperature should not be exceeded.

3. — Possible limitations may be specified by the boiler manufacturer or the contract.

4. — Deviations of a few percent in the extraction pressures as compared with the design values normally have a negligible effect on the overall performance. Should there be disproportionately large deviations in the extraction steam flow suggesting malfunctioning of the heaters, the effect on the overall performance may be serious, and agreement should then be reached on the course to be followed.

5. — If the test exhaust pressure deviates from that specified by more than 2.5% or 3 kPa, whichever is larger, the exhaust pressure correction should be verified by test on demand by one of the parties.

3.8.4 *Reading of integrating measuring instruments*

The mean values of the electrical output and the mass flow can also be determined by integrating measuring instruments by dividing the difference in the readings at the beginning and at the end of a test run by the corresponding time interval.

All integrating measurement instruments should be read simultaneously. Related indicating measurement instruments should be read at or nearly at the same time.

It is advisable to take simultaneous readings of all integrating instruments at regular intervals during the test run. This will enable checks for consistency to be made and permits the period for evaluation to be adjusted, if required, after the conclusion of the test run.

All observations should begin somewhat before and stop somewhat after the intended test period, provided all operating conditions remain constant.

3.8.5 *Alternative methods*

Alternative methods are presented in these rules for conducting certain details of the test. The test report shall state which alternative has been employed.

3.8.6 *Recording of tests*

Each observer shall record his actual observations. All records shall be made with carbon copies, at least in duplicate, or by mutual agreement be photo-copied immediately after each test. Immediately after the test each interested party shall receive a complete set of records.

3.8.7 *Additional measurements*

It is recommended that one or more stage pressures and temperatures be observed during the tests, since these may serve as a means of disclosing reasons for inconsistencies between tests.

3.8.8 *Preliminary calculations*

Preliminary calculations of corrections and test results shall be conducted immediately after the test in order to confirm the validity of the data taken.

3.8.9 *Consistency of tests*

Tests in a series shall be deemed inconsistent if the results differ from those of other tests at the same point of output and corrected to the same operating conditions, by more than 0.25%.

Should serious inconsistencies arise, either during a test or during the computation of results from a series of tests, the test or tests shall be rejected, in whole or in part, unless otherwise agreed.

3.9 *Repetition of acceptance tests*

Should the acceptance test result be unsatisfactory, the supplier shall be given an opportunity to make modifications and to repeat the test at his own expense. A repetition may also be requested by one of the parties to the contract if justified by doubts about the results.

If the supplier, for reasons which are his own responsibility, has made modifications following the acceptance test which make it probable that guarantee values will no longer be met within a reasonable margin, the acceptance tests may be repeated at the request of the purchaser.

4. Measuring techniques and measuring instruments

4.1 *General*

4.1.1 *Measuring instruments*

The instruments generally required for an acceptance test of a steam turbine are as follows (see Figures 2 and 3 for typical arrangements):

a) When testing a turbine separately, a dynamometer of a type suitable for the purpose.

b) For a turbine-generator, instruments for the determination of the electrical output and power for excitation if separately supplied and for other auxiliaries mentioned in 4.2.3.

c) Flow measuring devices.

d) Bourdon or deadweight gauges, manometers, U-tubes or transducers for measuring pressures or pressure differences.

e) Suitable instruments for determining temperatures.

f) Means to determine the dryness fraction of steam if it is not superheated.

g) Mercury manometers or columns or transducers for determining vacuum or absolute pressure.

h) Means for determining leakage flow of steam or water to or from glands.

i) Measuring means for determining condenser cooling water leakage and, if necessary, condenser air leakage.

j) Barometer (see 4.4.6).

k) Thermometers for determining temperature of mercury columns, manometers, barometers, exposed stems of glass thermometers and for measuring temperatures of water in volumetric measuring tanks, if employed.

l) Pressure gauge, thermometer and water meter, or its equivalent, for measuring make-up feed when admitted to the system.

m) For determining heater drain flows, liquid measuring means or, alternatively, pressure gauges and temperature measuring instruments as may be agreed upon for determining heater drain flows by heat balance methods.

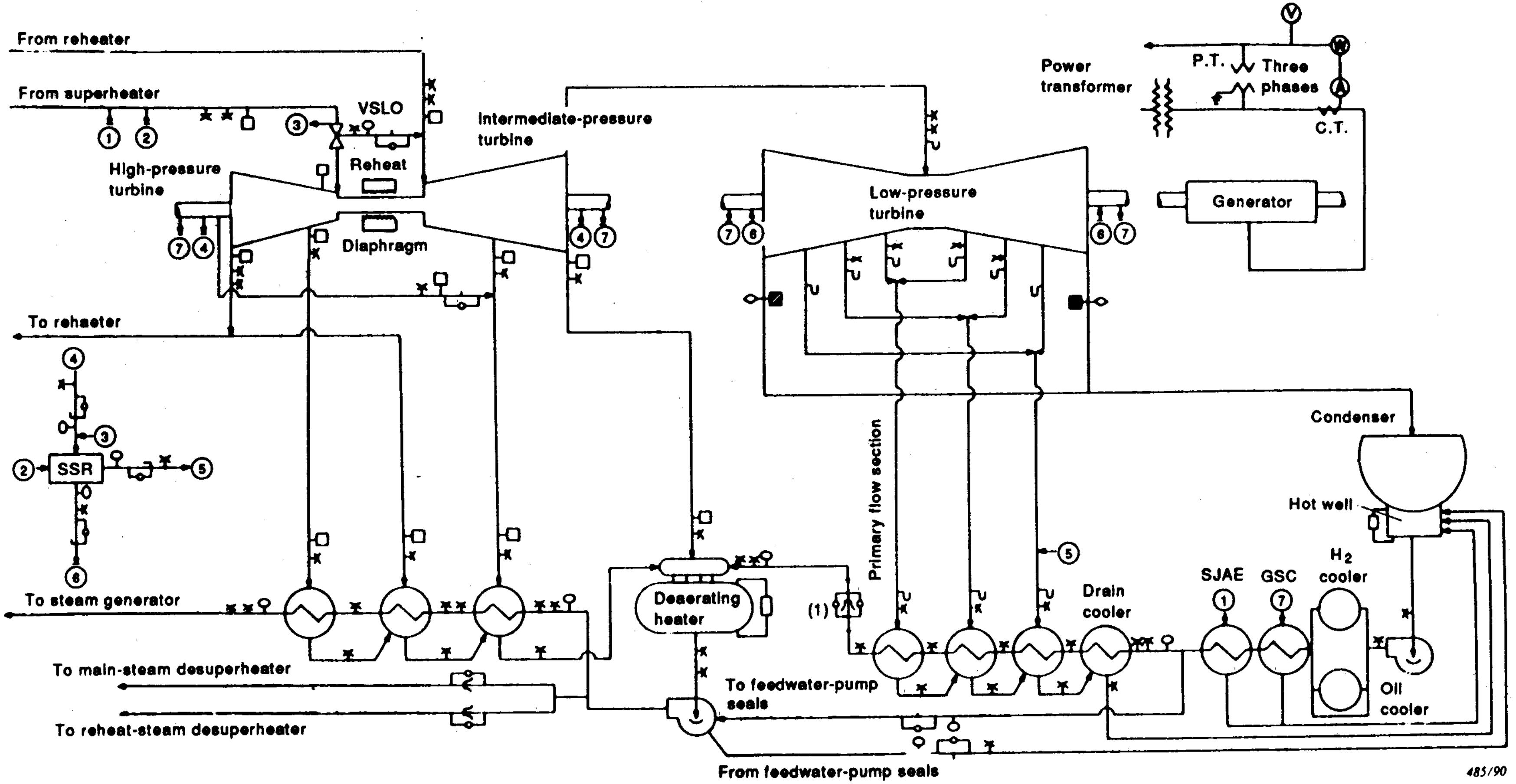
n) Speed indicator, as defined in 4.9.

o) Master clock with synchronized signalling system or, alternatively, synchronized clocks or watches.

p) Instruments as necessary to indicate or record the operating conditions of the generator at the time of the test.

q) Means such as weirs, meters or Venturi tubes, for determining the flow of condenser cooling water and thermometers for measuring its temperature, if the guarantee is based upon the flow and temperature of condenser cooling water (see also 4.3.9).

r) Means such as tanks, Venturi tubes, nozzles or orifices for the measurement of the flow of water discharged from any water separation equipment located after the point at which the initial steam pressure should be measured, if this flow is not included in another measurement.



✱	Thermocouple or resistance thermometer
♀	Calibrated Bourdon gauge
∪	U-tube
☐	Deadweight gauge
⊸	Orifice and manometer
⊸	Nozzle and manometer
⊸	Impact and static taps with U-tubes
◇	Absolute pressure
■	Basket tips in exhaust hood
♁	Level gauge

Refer to 4.1.5 regarding caution on use of mercury

Ⓦ	Wattmeter
Ⓐ	Ammeter
Ⓥ	Voltmeter
VSLO	Valve-steam leakoff
GSC	Gland-steam condenser
SJAE	Steam-jet-air ejector
SSR	Steam-seal regulator
CT	Current transformer
PT	Potential transformer

FIG. 2. — Diagram showing location and type of test instrumentation (high-pressure feedwater heater supplied with superheated extraction steam).

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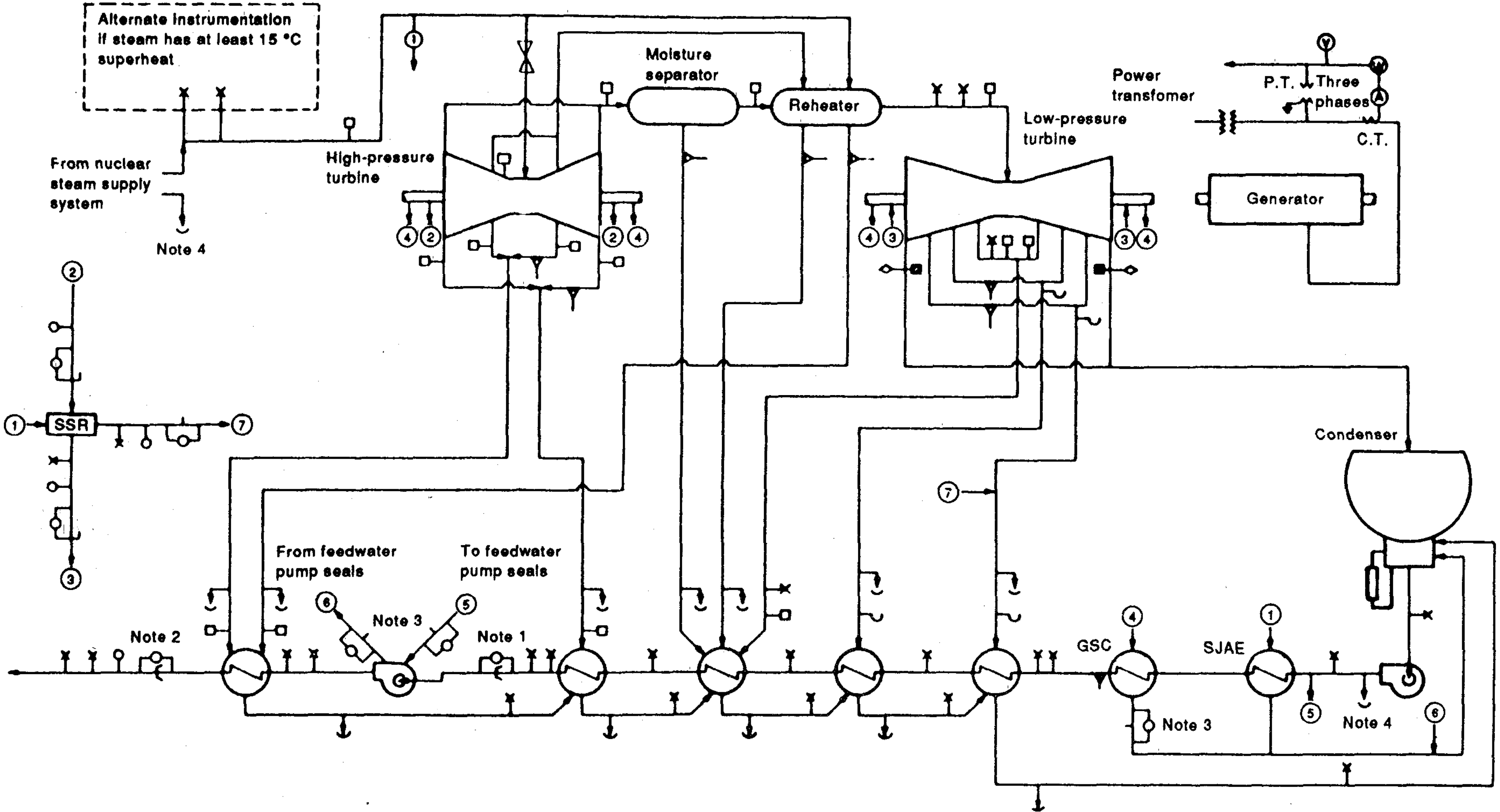
[1] Either location is acceptable.



Thermocouple or resistance thermometer
Calibrated Bourdon gauge
Deadweight gauge
U-tube
Orifice and manometer
Nozzle or Venturi and manometer
Impact and static taps with U-tubes
Absolute pressure gauge
Basket tips in exhaust hood
Tracer injection
Water sample
Level

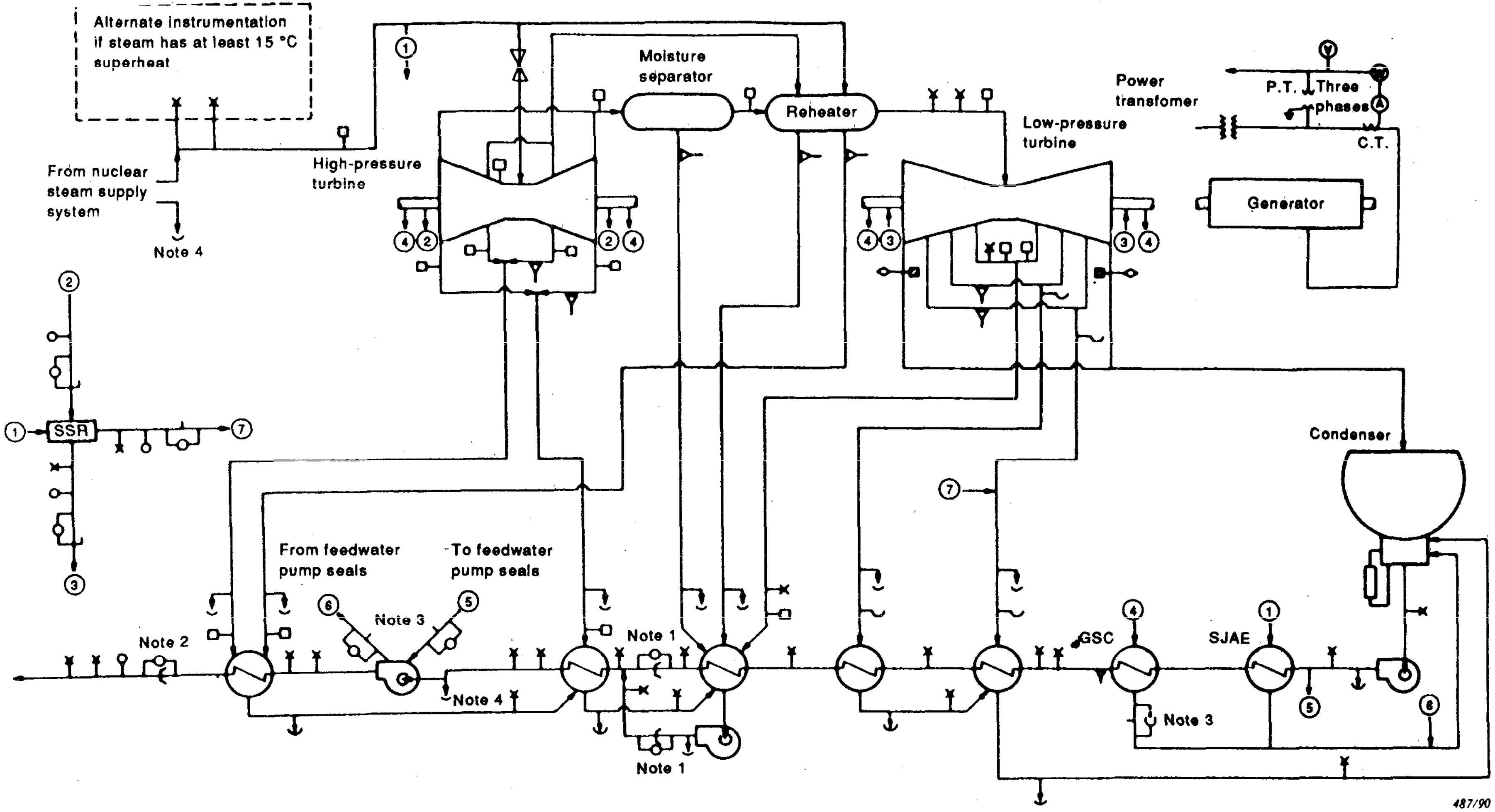
Refer to 4.1.5 regarding caution on use of mercury (orifice and manometer; nozzle or Venturi and manometer; impact and static taps with U-tubes)

Ⓦ	Wattmeter
Ⓐ	Ammeter
Ⓥ	Voltmeter
GSC	Gland-steam condenser
SJAE	Steam-jet-air ejector
SSR	Steam-seal regulator
CT	Current transformer
PT	Potential transformer

Notes

1. – Recommended primary flow measurement when heater leakage is measured by tracer.
2. – Recommended alternate primary flow measurement. See 4.2.2*c)* for inspection requirements.
3. – A calibrated turbine meter may be used where flashing might otherwise be a problem or where flow rate is less than 5% of primary flow.
4. – Omit water sample if main steam has at least 15°C superheat.

FIG. 3a. — Diagram showing location and type of test instrumentation (heater drains cascading to condenser; tracer technique for flow measurement).



Thermocouple or resistance thermometer
Calibrated Bourdon gauge
Deadweight gauge
U-tube

Refer to 4.1.5 regarding caution on use of mercury:

Orifice and manometer
Nozzle or Venturi and manometer
Impact and static taps with U-tubes

Absolute pressure gauge
Basket tips in exhaust hood
Tracer injection
Water sample
Level

Ⓦ	Wattmeter
Ⓐ	Ammeter
Ⓥ	Voltmeter
GSC	Gland-steam condenser
SJAE	Steam-jet-air ejector
SSR	Steam-seal regulator
CT	Current transformer
PT	Potential transformer

Notes

1. – Recommended primary flow measurement when heater leakage is measured by tracer.

2. – Recommended alternate primary flow measurement. See 4.2.2*c)* for inspection requirements.

3. – A calibrated turbine meter may be used where flashing might otherwise be a problem or where flow rate is less than 5% of primary flow.

4. – Omit water sample if main steam has at least 15°C superheat.

FIG. 3b. — Diagram showing location and type of test instrumentation (heater drains pumped forward; tracer technique for flow measurement).

4.1.2 *Measuring uncertainty*

The measurement of each quantity entering into the computation of the test result is liable to some degree of error. The test result is subject to a degree of uncertainty depending on the combined effect of all the errors of measurement.

Of the various measurements entering into the calculation of the test thermal or thermodynamic efficiency the two most important are the electrical power output and the main steam flow. A given percentage error in the measurement of the electrical power output causes an equal percentage error in the calculation of the thermal or thermodynamic efficiency. The same is substantially true of a given percentage error in the determination of the main steam flow.

The measured value of the main flow shall be adjusted to take account of various secondary flows, which are necessary for the operation of the plant (see 4.3.1 and 4.3.6). There are also many extraneous flows that shall be isolated or measured (see 3.4.4.1 and 3.4.4.2) and in the end there is almost certain to be some leakage unaccounted for (see 4.3.6.9).

Further uncertainties in the calculated thermal or thermodynamic efficiency arise from errors in measuring the terminal conditions listed in 6.4., especially the initial and reheated steam temperatures. Error in measuring the final feed temperature will also affect the calculation of the thermal or thermodynamic efficiency. These errors are taken into account in the value for inaccuracy of enthalpy determination given in the example below.

To estimate the probable error in the calculated thermal or thermodynamic efficiency, it is recommended that the combined effect of the various errors of measurement be taken as the square root of the sum of the square of all the separately calculated errors in thermal or thermodynamic efficiency due to each error of measurement. As an illustration of the probable error that results from the values of errors in the main measurements, which can be achieved by careful observation of all requirements of this recommendation under favourable conditions of the plant and its operation, the following example is given.

Error of thermal efficiency resulting from measurement inaccuracy of:

Electrical power		±0.1 %
Flow measurement		
Primary flow	±0.2%	
Secondary flows	±0.1%	
Unaccounted for	±0.1%	
Combined error due to flow measurements		±0.25%
Determination of enthalpy differences		±0.1 %
Combined probable error of thermal efficiency test result		±0.3 %

4.1.3 *Calibration of instruments*

Instruments shall be calibrated before the test. Such instruments shall be recalibrated after the test as specified hereinafter or agreed between the parties. A certificate of calibration by a recognized authority certified as to the date of the test shall be acceptable.

4.1.4 *Alternative instrumentation*

By mutual agreement of the parties interested in the test, advanced instrument systems such as those using electronic devices or mass-flow techniques, may be used as alternatives to the mandatory instrument requirements, provided that the application of such systems has demonstrated accuracy equivalent to that required by these rules.

4.1.5 *Mercury in instrumentation*

Mercury and compounds of mercury may react with component materials and cause environmental problems. The very low vapour pressure of mercury presents a serious health hazard if spillage occurs. The greatest care and strict adherence to all applicable regulations concerning mercury is necessary. If mercury is used the following precautions should be taken:

a) Keep instrument valves closed except during test runs.

b) Install quick closing solenoid valves in instrument pressure sensing lines to close automatically on system upsets.

c) Employ double mercury traps.

d) Locate the primary flow element in the low temperature part of the feed water cycle of nuclear plants where it is remote from the steam supply system.

4.2 *Measurement of power*

4.2.1 *Determination of mechanical turbine output*

The mechanical output of the steam turbine can be determined by one of the following four techniques:

a) By measuring the output at the generator terminals (see 4.2.4) and adding the generator losses.

b) By measuring torque and speed.

Absorption or torsion dynamometers are permissible, provided precautions are taken in their construction and use to ensure accuracy. This includes electric or eddy-current generators, the input of which is measured by the reaction of the stator.

If auxiliary power services of the turbine, such as governor and lubricating oil pumps, etc. are driven from an external energy supply, their power requirements shall be deducted from the turbine output at the coupling in order to determine the net output at the turbine coupling.

c) By establishing an energy balance of the steam turbine.

The output is derived from the algebraic sum of all energy flows passing through the envelope around the steam turbine.[1]

d) By establishing an energy balance of a driven machine (e.g. compressor, pump).

The output is derived from the algebraic sum of all energy flows passing through the envelope around the driven machine.[1]

4.2.2 *Measurement of boiler feed pump power*

For a complete evaluation and for correction of the test results according to the guarantee definition it is normally necessary to measure the power consumed by boiler feed pumps. It corresponds to the increase in the enthalpy of the water[2], and possibly the power consumed by the hydraulic couplings and speed changers if the pumps are driven directly from the mainshaft, or by an auxiliary steam turbine driven by a bleed from the main turbine.

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[1] Insignificant energy flows, for example heat dissipated to the environment due to conduction and radiation, can in most cases be estimated with sufficient accuracy and need not be measured.

[2] In many cases, mechanical losses and heat losses of the pump can be neglected.

Without using dynamometers:

a) If the pumps are driven by electric motors, the power consumed by the pumps may be found from the power consumed by the motors, taking into account the efficiency of the latter, and possibly from measurement of the power consumed by the hydraulic couplings and speed changers.

b) If the pumps are driven directly from the mainshaft, the power consumed by the pumps and the power consumed by the hydraulic couplings and speed changers should be measured.

c) If the pumps are driven by an auxiliary turbine, the total power consumed may be evaluated by measuring the steam flow and the rating data given by the turbine manufacturer, or by direct measurement as in *b)*.

An example is given below in which a boiler feed pump is driven from the mainshaft via hydraulic coupling and a speed changer (see Figure 4), showing how it is possible to measure directly the power consumed by the pump and that consumed by the coupling and the speed changer.

The power-transmitting and lubricating oil is cooled in heat exchangers using water as a cooling medium. Changes resulting from any variation in this arrangement should be agreed upon prior to the test. The illustration is for one pump, but the same measurements will be necessary for each in service. In some cases it may not be practicable to measure the individual water flow through each pump or the injection water flows to and from each pump. In such cases, the power for each individual pump cannot be accurately determined; however, the total power consumed by the boiler feed pumps in service is all that is needed for an overall test.

The pump power is best determined from the rise in specific enthalpy across the pump multiplied by the mass flow.

$$P = (\dot{m}_{10} h_{10} - \dot{m}_{g} h_{g}) + (\dot{m}_{go} h_{go} - \dot{m}_{gi} h_{gi}) \qquad (7a)$$

The power equivalent of the bearing, gear, and hydraulic-coupling losses, as determined from the heat picked up by the oil-cooling water.

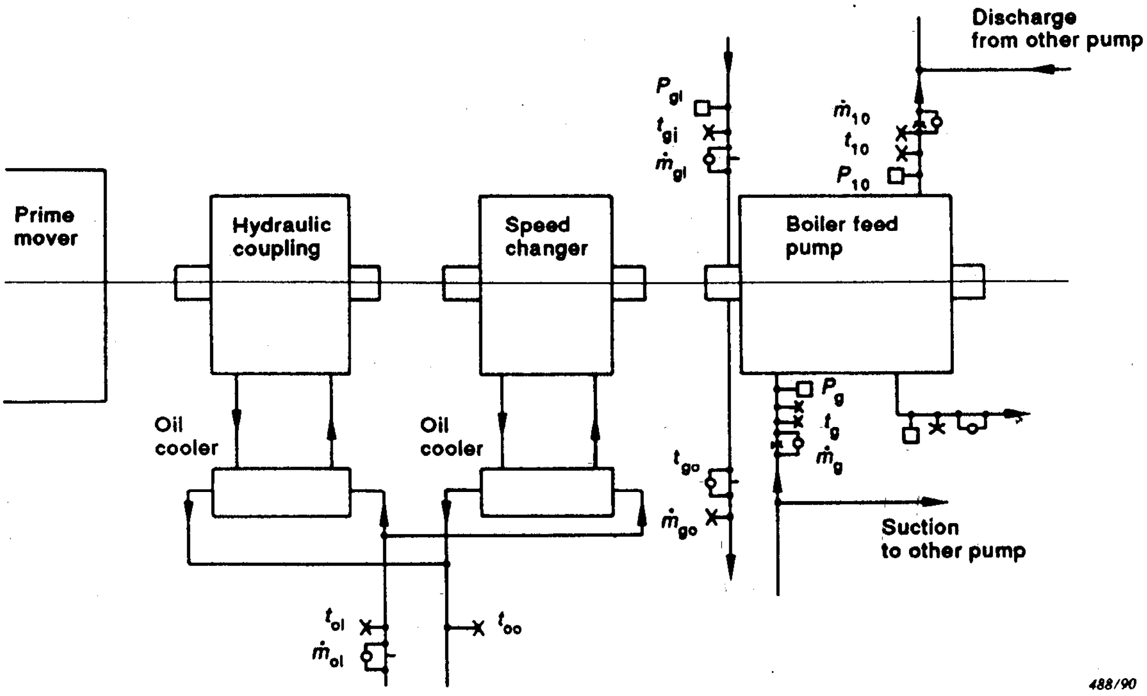
$$P_{mech} = \dot{m}_{oi} (h_{oo} - h_{oi}) \qquad (7b)$$

The symbols have the meanings shown in Figure 4.

Values of h in terms of pressure and temperature are given in current steam tables.

Since the temperature rise across the pump is small, a high degree of precision is required in the temperature measurements. In the absence of precise measurements, values of pump efficiency supplied by the manufacturer may be used in conjunction with the measured mass flow and pressure rise, but unless they are based on tests over the full range of load they may be open to question.

Sealing water flow and/or injection water flow has to be duly considered in the determination of the mass flow. The radiation losses are in general negligible.



gi = gland injection water inlet
go = gland injection water outlet
oi = oil cooler inlet water
oo = oil cooler outlet water

FIG. 4. — Typical instrumentation for measurement of boiler feed pump power.

4.2.3 *Determination of electrical power of a turbine generator*

The net power of a turbine generator is defined by the following formula:

$$P_g = P_b - P_a \qquad (8)$$

Where an auxiliary of the turbo-generator is driven by an electrical motor, the power P_a is the power delivered to the motor. This applies whether the power is derived from the generator terminals downstream of the point where P_b is measured or from a separately generated supply.*

Where an auxiliary of the turbo-generator is driven by other means, for example a pump or exciter driven by a prime mover, the power P_a is the power input in the coupling.

Where excitation is derived from the generator terminals at a point downstream of the point where the power P_b is measured or from some other source, P_a is the power input to the excitation equipment.

When the turbine generator, condensing and feed water heating plants are guaranteed as a combined unit, the power requirements of the condenser and feed water heating auxiliaries shall be treated in accordance with the terms of the contract.

4.2.4 *Measurement of electrical power*

For a three-phase generator with neutral directly earthed (grounded) or with 4-line system, the unit power shall be measured by the three-wattmeter method.

For a three-phase generator with neutral earthed (grounded) through resistance, reactance, or transformer with resistance, the unit power may be measured by either the two-wattmeter method, but preferably by the three-wattmeter method. In all instances, watthour meters can be used in place of wattmeters.

A double measurement of the electrical power, if practicable, including duplication of voltage and current transformers, has advantages for improvement of accuracy.

4.2.5 *Electrical instrument connections*

The instrument transformers shall be connected into the lines from the generator as near to the generator terminals as practicable and on the generator side of any external connections by which power can enter or leave the generator circuit.

The leads to the meters shall be arranged in such a manner that they will not influence the meter readings by reason of inductance or any other like cause. Inductance may be eliminated by braiding the wires of each pair of conductors for at least 1 m from the position where the instruments are located. It is desirable to check the whole arrangement of meters for stray fields, not only from the instrument leads but also from any other source.

The calibration of the transformers shall be made wherever practicable with the same instruments and wiring impedance as in the test.

The wiring influence of the voltage circuit shall not cause a significant error of the power indicated in the guarantee issued for the turbine generator. The wire thickness and length shall be chosen accordingly, taking into account the resistance of the safety fuses to be used in the voltage circuit. The errors due to wiring resistance (including fuses) shall always be taken into account.

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* This does not refer to IEC 34-2.

4.2.6 *Electrical instruments*

Singlephase or polyphase portable precision wattmeters of an accuracy class of not more than 0.1 % or singlephase or polyphase portable precision watthourmeters with an inaccuracy less than 0.1 % of reading value or better shall be used with appropriate voltage and current transformers for measuring electrical output.

Portable ammeters, voltmeters and wattmeters shall be included in the measuring circuits to establish that the generator load conforms to rated conditions during the tests and to measure the current, voltage and power factor.

For the environmental conditions of the instrumentation see 3.2, Item *e)*, second paragraph.

The recording time of watthourmeters shall be measured in a manner such that any inaccuracy will not exceed 0.03 %. Watthourmeter readings shall be recorded during the test at regular intervals (at least every 5 min).

4.2.7 *Instrument transformers*

Instrument current and potential transformers of appropriate rating and accuracy characteristics, specially intended for test purposes, should be used. Values of ratio and phase-angle corrections for the conditions of loading equivalent to the test instruments and leads used during the test shall be obtained by a recognized calibration procedure to cover the range of test values of current and voltage. Instrument transformers shall be used which have no burden other than that of the test instruments and leads. Otherwise it has to be confirmed that the permissible burden is not exceeded.

4.2.8 *Comparison measurement and recalibration of instruments and transformers*

In case of measurement of electrical output by a single instrument per phase, all wattmeters and/or watthourmeters shall be recalibrated individually with a standard meter taken to the site of the test, immediately after each test run. The other instruments shall be compared similarly, if required by either party.

If a wattmeter or watthourmeter is compared after the test, in conformity with 4.1.3 and the correction at any point is found to differ by more than an assigned value (to be, for the most accurate work, 0.15% of full scale value for wattmeters or of reading value for watthourmeters) an additional comparison or comparisons shall be made immediately at this point until the corrections do not differ among themselves by more than 0.1 % of full scale value for wattmeters or of reading value for watthourmeters. The average of these results shall then be taken as the corrections at the point in question at the time of this comparison. In the event that the excess variation (0.15% of full scale value for wattmeters or of reading value for watthourmeters) still remains, the new value found shall be taken as correct and all test runs in which this scale point may cause error shall be investigated.

In case of a double or multiple measurement of the electrical power per phase, the different results shall be compared and the average value will be taken for the final computation. If the difference is greater than 0.15% a comparison measurement of the instruments as described above shall be made.

Recalibration or re-checking of current and potential transformers will not be necessary, unless serious doubts arise as to the reliable functioning of a transformer. It is advisable to calibrate the transformer in place. Consequently it should not be disconnected as the cause of deviations may be found in the contact resistances in the wiring, loose connections, etc.

4.3 *Flow measurement*

4.3.1 *Determination of flows to be measured*

In conducting an acceptance test, the flows to be measured can be divided into two categories:

Primary flow:	Flow which is in direct proportion to the power output and which shall be measured with a high degree of precision. The necessary precision can usually be achieved only by measurement of water flow. To verify the accuracy of the primary flow, and/or to check for internal leakages and other undiscovered deficiencies of the cycle flow conditions, making two measurements of flows at different places and comparing the results can be advantageous (see 4.3.3).
Secondary flows:	Flows which are necessary for the operation of the plant and which shall be taken into account in the adjustment of the measured values of the primary flow, in order to determine the turbine initial steam and reheat steam flows.

4.3.2 *Measurement of primary water flow*

The measurement of primary water flow may by made:

a) by means of calibrated nozzles or orifices upon agreement of the parties interested in the test (4.3.2.1, 4.3.3);

b) by direct weight by means of tanks and suitable scales;

c) by means of calibrated volumetric measuring tanks.

It is seldom practicable or economical to employ weigh tanks or volumetric tanks for the testing of the large units installed in modern power stations; the usual method of determining flows is by means of differential pressure devices.

4.3.2.1 *Differential pressure devices for measuring primary water flow*

Calibrated differential-pressure devices shall be used to measure flow if the devices have demonstrated their repeatability and accuracy to the mutual satisfaction of both parties.

A choice can be made from among the following recommended devices:

a) sharp-edged orifice plate (reference: ISO 5167);

b) wall tap nozzle (reference: ISO 5167);

c) elliptical throat tap nozzle. This device is not covered by ISO 5167 but it has now become established as an instrument of precision. Full details are given in Appendix B.

The recommended ranges of diameter ratio (d/D) are as follows:

nozzles	0.25 to 0.50
orifices	0.30 to 0.65

During the passage of the water through orifices and the nozzles, either the pressure shall remain not less than 250 kPa above the saturation pressure which corresponds to the measured temperature, or the temperature of the flow shall remain not less than 15 K below the saturation temperature corresponding to the lowest measured absolute pressure.

Requirements in 4.3.2.2 shall be satisfied.

4.3.2.2 *Calibration of differential pressure devices for water flow*

Preferably each pressure-difference device should be calibrated with flow conditions corresponding to the same range of Reynolds number as will prevail in the turbine tests. Actually, however, the laboratory facilities at present available are not capable of achieving values of Reynolds numbers as great as those associated with test flow conditions for modern large steam turbines. The problem, therefore, is how best to extrapolate from values of discharge coefficient determined in the largest scale laboratory tests practicable. The extrapolated value shall not differ by more than 0.25% from the curve coefficient at the highest Reynolds Number attained during calibration.

Calibration is to be conducted with the upstream and downstream piping comprising the flow section to be used in the test, including the flow straightener if used.

It should be demonstrated during calibration that each pressure difference device is capable of repeating selected calibration points over the pertinent flow range within ±0.1%.

a) Sharp-edged orifice plate

For sharp-edged orifices the discharge coefficient C_d is in the region of 0.6 and falls slowly with increase of Reynolds number. Values of the flow coefficient α are given in ISO 5167 as a function of the upstream Reynolds number R_e, the area ratio (orifice/pipe) squared, and the tapping position from which the value of the discharge coefficient C_d can be determined.

When C_d is plotted against

$$\left[\frac{10^6}{R_e}\right]^{0.75} \text{ for sharp edged orifice plates,}$$

$$\left[\frac{10^6}{R_e}\right]^{0.5} \text{ for nozzles,}$$

a straight line is obtained. The slope and position of the line obtained shall be such that the difference between the value of C_d derived from this line at the test condition and corresponding value derived from the reference curve shall not exceed ±0.25%.

b) Wall tap nozzle

The reference curve should be derived from the data given in ISO 5167 and the calibration should not deviate from the reference curve by more than ±0.25%. Extrapolation beyond the range of the calibration facilities is permissible, subject to provisions of a generally similar nature to those applying to throat-tap nozzles.

c) Throat tap nozzle

Refer to Appendix B.

4.3.2.3 *Inspection of primary-flow device*

The primary element and its flow section shall be known to be clean and undamaged throughout the test period. This shall be determined by inspection immediately before and after the test.

4.3.3 *Installation and location of differential pressure devices*

The minimum requisite lengths of straight piping upstream and downstream of the orifice or nozzle are influenced by the configuration of the piping before and after the straight sections; for particulars see the ISO Standard quoted. Upstream of a throat-tap nozzle a flow straightener is required as indicated in Appendix C.

In special circumstances, for measurements with other pressure difference devices the application of a flow straightener shall be considered. The incorrect use of flow straighteners may lead to errors (see Appendix C).

Any calibration of a measuring element shall be carried out with the complete straight piping section upstream and downstream, the flow straightener included.

It is advisable that one of the primary flow measuring devices be located in the system at a point where the temperature is less than 150 °C to minimize temperature effects, that is any resulting distortion of the measuring element. Moreover, higher water temperatures result in higher Reynolds numbers which sometimes require a greater extrapolation of the coefficient of discharge curve. In order to maintain the initial characteristics of the flow-measuring devices, it is desirable to make the following provisions:

- the flow-measuring devices shall be made of corrosion-resistant material;
- where the flow-measuring devices are located in high temperature circuits, special precautions shall be taken to avoid their distortion (measuring devices in the same material as the pipe or arrangements made to ensure their free expansion).

When the flow-measuring device is installed in a vertical run of pipe, a correction shall be made to account for differences in altitude between the two pressure-tapping points and differences in density between the water flowing through the flow-measuring device and the water in the pressure-tap lines.

To minimize the difficulty of obtaining steady flow, the flow-measuring device should not be located at a pump discharge. Advantage should be taken of the damping effect of any existing heat exchangers and long lengths of pipe in the cycle in locating the flow-measuring device. The flow-measuring device should also be located to eliminate the effects of recirculating and bypassing flows. If this is not possible, extraneous flows shall be measured with an accuracy sufficient that error in primary flow is less than about 0.1 %.

Figure 3 shows the location of flow instrumentation for a typical cycle using wet steam with all heater drains cascading to the condenser. The primary flow measurements are located in the low-pressure heater inlet and high-pressure heater discharge piping and serve as a check on possible leakage. If these measurements disagree by more than about 0.1 %, the isolation of the cycle should be rechecked, flow calibration curves should be investigated, and the possibility of heater leakage considered. In the event that this discrepancy persists and indicates an impossible negative heater leakage condition, the condensate flow measured should be considered as the only primary flow measurement because of the more favourable temperature range. Feedwater flow should then be derived from this condensate measurement. If the discrepancy indicates heater leakage, the feed-water flow measurement should be used as the primary flow. The double flow measurement will not be required if heater leakage is determined by using the radioactive tracer technique. Other tracer methods may be used if the accuracy is comparable to the double flow measurement.

If the feedwater cycle includes a deaerator, it is recommended that the condensate flow entering it be measured. This eliminates any possibility of heater leakage recirculating through the flow-measuring device. If the cycle has no deaerator, it is recommended that the flow be measured after it has passed through the low-pressure heaters and before it enters the boiler feed pump. If the drains from the high-pressure heaters join the main condensate flow upstream of the flow-measuring device, it will be necessary to measure the total drain flow from the high-pressure heaters and calculate the extraction steam by heat balance around the heaters to determine the high-pressure heater leakage.

For turbines using wet steam and heaters with pumped-ahead drains, the double flow measurement is again required to determine if any of the heaters leak. The location of the low pressure flow measurement will depend on the cycle arrangement. Heater leakage can also be measured by using the tracer method.

4.3.4 *Differential pressure measurements*

The measurement of the differential pressure necessitates particular care. Primary flows shall be determined by at least two independent differential pressure measurement systems installed with the precautions listed below and as illustrated in Figure 5.

a) Connecting piping used between the pressure taps and the manometers shall be not less than 6 mm inside diameter tubing of such material to avoid resistance damping inside the piping. This tubing shall run horizontally for 1 m from the flow-measuring device and then slope down continuously without loops to the manometers. The connecting piping shall be shown to be tight by a pressure test.

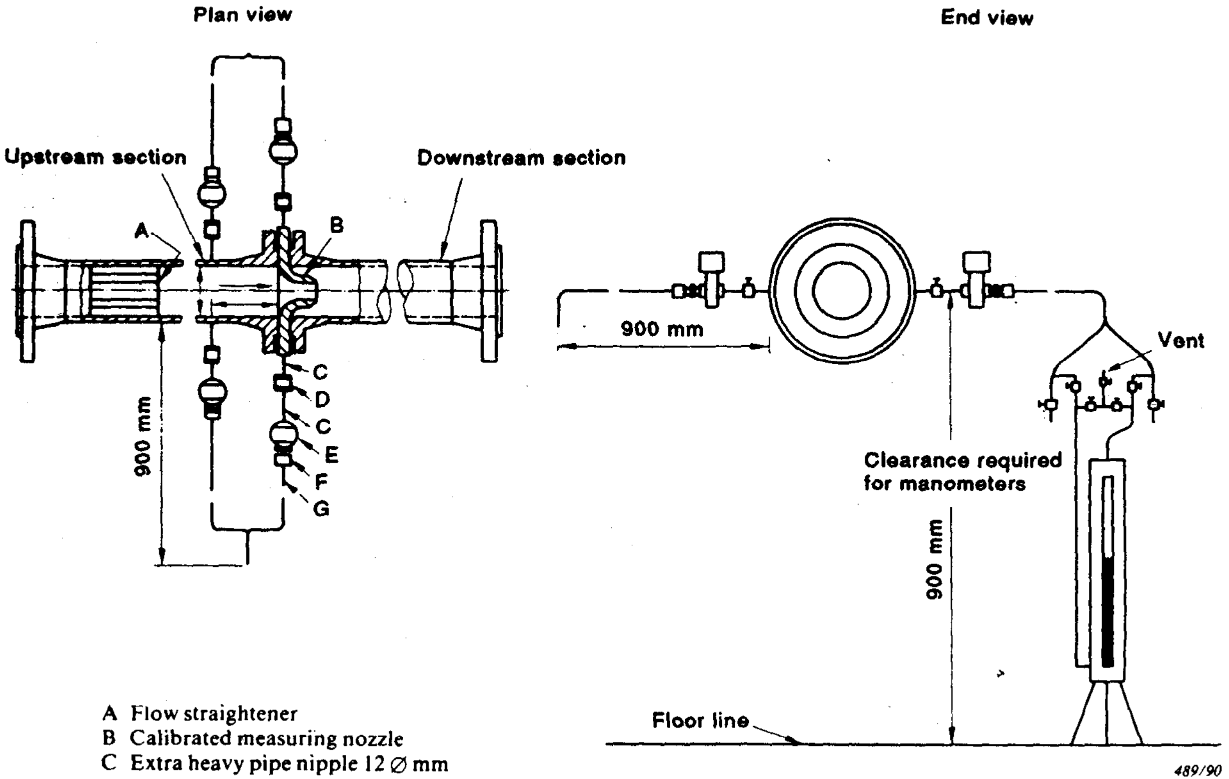
b) The length of piping between the flow-measuring device and manometers should not exceed 7.5 m and is to be uninsulated.

c) Precautions shall be taken when running the manometer piping to ensure that the temperature difference between the fluid in the two lines connecting the primary element and each manometer does not exceed 2 °C. It is recommended that the piping be bundled and run in such a manner as to minimize heat transfer to these pipes from an external source.

d) The manometer piping shall be well flushed before the manometer is connected. The manometer connections shall include valves, tees and bleeders, as shown in Figure 5, suitable for shutting off manometer piping or venting at any time during the test. Sufficient time should be allowed for the water legs in the connecting piping to reach temperature equilibrium.

e) Zero-displacement solenoid-operated valves may be installed as shown in Figure 5, in each tube close to the primary element to eliminate mercury column movement during reading. These valves are to be closed for reading at prescribed intervals without regard to the position of the mercury column. Other means of obtaining instantaneous readings may be employed if they do not introduce errors in the reading. With transducers, solenoid valves should not be used.

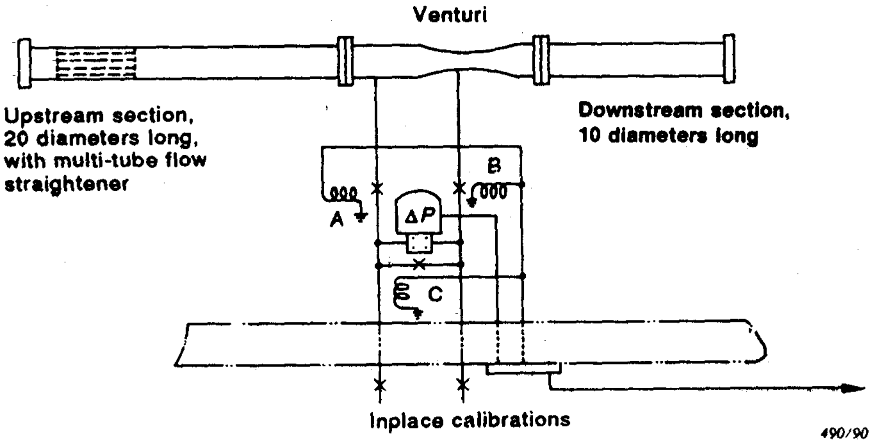
f) The manometers should be located at a lower elevation than the primary-flow element. However, when this is impracticable, special precautions shall be taken to ensure proper venting of the system. Suitable venting pots shall be installed above the manometers with valves for venting. Also, a temperature seal (loop to piping) shall be installed between the primary element and the manometers.



- A Flow straightener
- B Calibrated measuring nozzle
- C Extra heavy pipe nipple 12 ∅ mm
- D Gate valve 12 ∅ mm
- E Solenoid actuated valve*
- F Pipe to 12 mm ∅ tube fitting
- G 12 mm ∅ tubing

* Not necessary with transducers.

FIG. 5. — Connection between flow section and manometers.


Venturi
Upstream section, 20 diameters long, with multi-tube flow straightener
Downstream section, 10 diameters long
A
B
ΔP
C
Inplace calibrations
490/90

A, B, C: Remote operated electro solenoid valves for calibration

10—50 mA (or equivalent) output to computer or portable data acquisition system

FIG. 6. — Test set-up designed for heater drain-flow measurements.

g) The differential manometers before and after each test run shall show a zero reading less than about 0.1% of the differential observed during that test run. At any time during the test run the average readings of the two manometers shall agree with one another within about 0.2%, after correction for any calibration difference between the two sets of taps.

h) The manometers should be 1.2 mm (or larger) bore precision-type and should be read with the aid of an antiparallax reader or other suitable means to within 0.25 mm. The mercury used shall be instrument-grade having less than one part per million of non-volatile residue. The manometer shall be scrupulously cleaned before the mercury is introduced.

i) If pressure-transducers are used, precautions *a)* to *g)* are applicable as for manometers. In addition, they shall be calibrated before and after the test. Each calibration shall be done by raising and lowering the pressure. The tests are to be calculated with the mean calibrated values.

Long term stability of the transducers shall be carefully recorded. The transducers selected for differential pressure measurement for primary flow measurement should have an error not greater than 0.005% of full scale plus 0,010% of reading. A quartz Bourdon tube transducer can meet these requirements.

4.3.5 *Water flow fluctuation*

Flow measurements shall not be attempted unless the flow is steady or varies only slightly with time. The maximum allowable average amplitude of the manometer deflection is 1% of the full load reading with higher frequencies than one-half the reading frequency and 5% for lower frequencies. Variations in the flow shall be suppressed before the beginning of a test by very careful adjustment of flow and level controls or by introducing a combination of capacitance, such as bypassing flow around the pump, and resistance, such as throttling the pump discharge, in the line between the pulsation sources and the flow-measuring device. Damping devices on the manometers do not eliminate errors due to pulsations and, therefore, shall not be used. If the pulsations exceed the above values after every effort has been made to suppress them, mutual agreement is required before the test can be started.

4.3.6 *Secondary flow measurements*

In addition to the primary flow measurements covered by 4.3.1 and 4.3.2, many secondary flow measurements are required. Because of differences in plant layout and the alternative positions of flow-measuring devices it is not possible to specify the accuracy required in each separate measurement. The parties interested in the test should decide what secondary flow measurements shall be made for the type of turbine installation concerned and then arrange for each measuring device to have an accuracy such that the combined effect of all errors in the secondary flow measurements would not cause more than 0.1% error in the test result. Consequently, if standardized measuring devices are used, calibration may not be necessary.

If the secondary flow-measurement is of steam, the following paragraphs apply:

a) In passing through the flow-measuring device, the steam shall remain superheated. Measurement shall not be attempted if the amount of superheat is less than 15 K at the smallest cross-section of the nozzle or orifice.

b) For the measurement of steam flow, venting pots should be installed at the same elevation as the primary element pressure taps and at a suitable distance to ensure proper condensation. The water levels have to be at the same elevation, otherwise differences are to be determined. The connecting piping to the venting pots should have a sufficiently large diameter to avoid the formation of water plugs,

c) The connecting lines to the manometer have to be installed with a continuous downward slope. After venting, time should be allowed for the water legs to form and cool. Special attention has to be paid to the proper formation of water legs at subatmospheric pressure.

4.3.6.1 *Extraction steam flows to feed heaters*

Provided that the extraction steam is superheated, the extraction flow can be determined by heat balance calculation. The accuracy of the result falls off as the temperature rise across the heater diminishes.

In wet steam cycles, extraction flows can be determined from heater drain flow measurements. At each measurement the error should not exceed 0.5% of the extraction flow.

This can be accomplished by using a calibrated flow measuring device. The heater drain flows can be measured using differential pressure devices; however, for the lowest pressure heaters, very little pressure drop is available. In these cases, Venturi tubes or other low head loss primary elements of the required accuracy should be used. The differential pressure across the nozzle, orifice plate or Venturi tube should preferably be measured with a transducer. The connecting piping between the transducer and the differential pressure device should be as short as possible to minimize damping errors due to unsteady flow and care shall be taken to eliminate air bubbles in this piping. Thus, it is possible that the transducers will be mounted in areas of high radioactivity which would require that pressure lines be run from the transducer to an uncontaminated area with appropriate remote-controlled valves to allow the transducers to be calibrated in place during the testing period, as shown in Figure 6. The calibrating reference should be a secondary standard where error does not exceed 0.25%. Heater drain flows are often very unsteady and to minimize errors due to such unsteady flow, the transducer output should be sampled at least every twenty seconds. The values used to determine flow for each measurement system should be based on the average of the square roots of the various readings. The uncertainty of this nozzle or Venturi/transducer/readout system is 0.25% at full-load and 0.5% at half load. In order to achieve and maintain the desired accuracy, the transducer should be shock-mounted in a temperature-controlled enclosure and in-place calibration provided during the test.

In sizing these Venturi tubes to avoid cavitation the best compromise between Reynolds number, pressure loss, diameter ratio, and deflection should be made without reducing the critical cavitation coefficient *K* below than 0.2, where:

$$K = \frac{P_{\text{throat}} - P_{\text{sat}}}{\frac{\varrho}{2} \cdot W^2_{\text{throat}}} \qquad (9)$$

The cavitation problem may be reduced by providing a loop or seal or increasing the length of the loop seal to put more head on the meter so that the critical cavitation coefficient *K* will be greater than 0.2.

If the heater drain flow is subcooled the cavitation problem is also reduced. The extraction wet steam flow can be detemined by a heat balance calculation, if the enthalpy of the extraction steam has been determined by the tracer method (see 4.7.2).

4.3.6.2 *HP heater drains*

When the main flow meters are at the deaerator outlet, unless the HP heaters have been checked for leakage, the flow should be metered by a device capable of an accuracy within ±1%. The flow meter should be situated in such a position that the minimum pressure is according to 4.3.6.1.

4.3.6.3 *Moisture separator and reheater drains*

It may not be possible to install a flow measuring device because the available head is less than that required to avoid cavitation, also for reasons of plant design or operation. In these circumstances, the tracer technique can be used to measure the flow with an accuracy that will not affect the heat rate comparison with guarantee by more than 0.1 %.

4.3.6.4 *Boiler feed pump turbine steam supply*

Steam consumption of a boiler feed pump turbine is preferably to be measured as condensate if a separate condenser is installed.

In a reheat cycle having a boiler feed pump driven by a turbine supplied with steam from the main turbine at a point upstream of the reheater, the steam supplied shall be measured to enable the flow through the reheater to be determined. The metering orifice or nozzle should be removable for inspection and/or recalibration.

Two independent manometers or transducers should be used for measuring the differential pressure unless pre-test checks have shown that there is very good agreement between the two readings.

4.3.6.5 *Turbine gland leakages*

If the steam leakage outwards from the high pressure glands of a reheating condensing turbine does not pass through the reheater but is returned to the system at some point beyond the reheater, these steam flows shall be measured separately, if practicable, by differential pressure devices. These flows should be considered when determining the heat supplied by the reheater.

If any glands, sealing against internal or external pressure, are provided with leak-offs to atmosphere or to a point that is extraneous to the turbine system, this flow shall be measured unless agreed to be negligible. Preferably it should be taken to a separate condenser and measured as condensate.

4.3.6.6 *Desuperheating spray water flow*

When spray water from the feed-heating system is used for regulating the reheat steam temperature the rate of flow of such water shall be measured. Also, if the initial steam temperature is similarly regulated, the rate of flow of spray water to the superheater shall be measured, except in the case that the water is drawn from a position downstream of the final feed heater and the last feed water flow measuring device.

4.3.6.7 *Boiler feed pump gland sealing and balance water flow*

The amounts of water supplied to the feed pump glands for sealing and cooling purposes and the amounts of leak-off water returning to various parts of the systems are liable to be considerable. These amounts may be direct additions to, or subtractions from, the main flow measurement. The number of boiler feed pump water flows to be measured will depend on the location of the main metering device. Calibrated or standardized measuring devices are required and it should be ascertained at the time of the test that they are in good condition.

4.3.6.8 *Stored water changes*

Changes in stored water quantities within the test cycle shall be taken into account in the assessment of the condensate/feedwater flows through the system.

Such stored water quantity changes will include those in condenser hotwells, deaerator storage tanks, feed heater bodies and any storage or drain tanks that cannot be isolated from the system.

Water level changes in all storage vessels should be measured by temporary scales rigidly fixed close to the sight glasses of the permanently installed level gauges, or, alternatively, by transducers used in conjunction with test data-logging equipment.

If the temperature of the water in a vessel is appreciably different from the ambient temperature and an external gauge glass is employed, e.g. a deaerator storage tank, the density of water in the gauge glass should be used in the conversion of water level change to mass change in the vessel.

Gauge glasses which are connected to vessels containing hot water should not be blown within a period of approximately half-an-hour before taking a reading, in order to avoid a false level indication due to a change of temperature in the water column.

Since time is a critical factor in the measurement of the water level changes, the test readings shall be closely synchronized with the signals for commencement and termination of a test.

4.3.6.9 *Leakage determination*

It will be necessary to use calculated values for internal pump leakages, shaft packing, valve stem leakages, and internal turbine leakages when it is not practicable to measure these flows.

4.3.7 *Occasional secondary flows*

Further secondary flows, which occur relatively rarely, or need not be measured, include the following:

4.3.7.1 *Ejector steam*

Steam jet air ejector steam flow can be calculated from the measured pressure and temperature of the steam supply and the known cross-sectional area of the jets. When the steam supply is wet it may be preferable to use the design flow rates given by the manufacturer.

The amount of steam removed from the condenser by the air removal means is generally negligible. Should it be measured, the method of measurement of this steam flow shall be agreed upon by the parties interested in the test.

4.3.7.2 *Make-up flow*

Make-up flow to the condensate system, if any, shall be determined by means of a nozzle, orifice or a Venturi tube, by means of a calibrated water meter or by a volumetric tank.

4.3.7.3 *Water seals*

Sealing water is used in connection with hydraulic glands or atmospheric exhaust valves, condensate pump glands, etc. As the seals have to be maintained, the flow of water used shall be measured and an appropriate allowance made.

Alternatively, seals whose leakage goes into the condensate system, including that for a wet air pump, may be sealed with condensate that has not reached the point where its flow is determined. Any overflows shall be returned to the same point. With this method no measurement of this leakage is necessary. It shall be ensured that there is no variable storage in the sealing system and no possibility of leakage of sealing water other than into the condensate system. If external leakage of condensate water from seals cannot be avoided, its flow shall be determined and added to the condensate flow.

4.3.7.4 *Auxiliary exhaust steam*

Any auxiliary exhaust steam that normally enters the condenser shall either be diverted elsewhere during the period of test or measured. In deciding upon the best position to install the measuring device, particular attention should be paid to the net head loss and the possibility of flashing in the throat.

4.3.8 *Density of water and steam*

The density of water which is required for calculation of mass flow rate is calculated from an accurately measured temperature and reasonably approximate pressure. The temperature shall be measured with a precision-calibrated instrument. If an extra instrument is used, it should be located at least 10 pipe diameters downstream of the primary element. For primary water flow it is also permissible to use the average of the discharge temperature of the upstream heater and the inlet temperature of the downstream heater, providing no extraneous flow enters between them, and the temperature is taken at least 10 diameters downstream from the heater outlet to ensure adequate mixing.

The density of steam which is required for calculation of mass flow rate is calculated from measurements of pressures, using a precision gauge, and temperature, using a precision instrument or resistance thermometer. The reference planes for the density determination are to be taken according to the calibration procedure or the standard of the flow measuring device.

4.3.9 *Determination of cooling water flow of condenser*

This flow is normally only required if condenser performance is included in the turbine generator performance guarantee.

In many cases a direct measurement is not possible or not practicable because of technical difficulties. The cooling water flow can be determined conveniently by a heat balance calculation.

The quantity of the condenser cooling water may be calculated. If measurement is feasible, one of the following methods may be used:

a) standardized nozzles or orifices in the pipe line;

b) Venturi tubes, or their equivalent in the pipe line;

c) current meters;

d) Pitot tubes, provided it is agreed that the differential head is sufficient to give the necessary accuracy;

e) weir-notch method.

Further measuring methods necessitating less installation effort are available and may be used with sufficient knowledge and care:

f) dilution methods using chemical or radioactive tracers;

g) ultrasonic techniques.

4.4 *Pressure measurement (excluding condensing turbine exhaust pressure)*

4.4.1 *Pressures to be measured*

The intitial pressure of steam supplied shall be measured in the steam line on the steam-generator side of, and as close as practicable to, the turbine stop valve and upstream of the strainer if this has been furnished by the manufacturer under the turbine contract. The initial steam pressure shall be measured in the pipe downstream from the parts which have not been furnished under the turbine contract, unless the turbine contract or specification states otherwise.

The steam strainer shall be known to be clean. If there is a doubt about its cleanliness, on the part of either of the parties to the test, it shall be examined prior to the test and cleaned if necessary.

Pressures should also be measured at the inlets to the HP, IP and LP cylinders of the main turbine, at the inlet and outlet of the boiler feed pump turbine (if integrated with the feed-heating system) and at both ends of bled steam lines; also at the suction and discharge of all pumps in the condensate and feed system.

Wherever practicable, pressure tappings shall be situated in straight runs of piping, remote from any flow disturbances.

The pressures measured during steam turbine tests shall be static pressures.

4.4.2 *Instruments*

Deadweight gauges, Bourdon tube type test gauges or mercury manometers shall be used. All of these instruments can be replaced by transducers of suitable measuring range and equivalent accuracy (see 4.4.2.5).

Pulsations of pressure shown shall not be damped by throttling on the gauge valve or by the use of commercial gauge dampers. A volume chamber may be employed.

4.4.2.1 *Measurement of pressure above 250 kPa (2.5 bar)*

For pressure above the range of liquid manometers, i.e. above approximately 250 kPa if mercury is being used, deadweight gauges are recommended. The freedom of the pistons to rotate shall be checked during the test.

4.4.2.2 *Measurement of pressure below 250 kPa (2.5 bar), but above atmospheric pressure*

For any pressure below 250 kPa, but above atmospheric pressure, a deadweight gauge, Bourdon gauge or preferably a mercury manometer may be used.

If mercury manometers are used for pressures below 250 kPa, but above atmospheric, then precautions to be taken are the same as those given in 4.4.2.3.

4.4.2.3 *Measurement of pressures below atmospheric pressure*

Mercury manometers (see 4.1.5) shall be used for measuring pressures below atmospheric.

The tubing for mercury manometers shall be high-grade lead-free glass, preferably not less than 10 mm bore in the region where readings will be taken.

Where small pressure differences must be measured with high accuracy, silicone oil may advantageously be used as the manometer fluid in place of mercury.

4.4.2.4 *Liquids for manometers*

The liquid used shall be suitable for the application, and be of known density.

Mercury used in manometers shall be pure and free from foreign matter of any kind. Pure mercury at 273 K has a density of 13 660 kg/m^3.

For important low pressure readings, the accuracies of which influence the results of the test, when a doubt arises as to the purity of the mercury in the manometer, pure distilled mercury shall be substituted. The purification of the mercury involves technical difficulties and should not be undertaken by persons inexperienced in this work.

4.4.2.5 *Transducers*

Accurate pressure measurements are possible with transducers provided that their use and care are well understood and that they are properly maintained and installed. It should be recognized that a transducer is, in general, a more delicate instrument than a dead weight gauge or a manometer, and it should be treated as such. Regardless of the transducer application it should be calibrated before and after the test.

The transducer should be located in a position which is free from vibration and dirt, and where there are not likely to be large changes in ambient temperature such as may be caused by an outside door.

If the transducer is sensitive to changes in environment such as temperature, the system should be given sufficient time (e.g. 2 h for quartz Bourdon type transducer) to stabilize before readings are taken. A zero reading shall be taken before and after each test run.

4.4.3 *Pressure tapping holes and connecting lines*

Holes for measuring pressures shall be drilled at right angles to the inner surface of the pipe. The inner rim of the hole shall be free from burrs, having its edge sharp and square. For a length of at least twice its diameter, the hole shall be straight and of uniform bore. Connecting pipes from this hole to the measuring instrument shall be free from scale, corrosion products or other obstructions.

4.4.3.1 *For pressures above 250 kPa (2.5 bar)*

The pressure hole mentioned in 4.4.3 above shall have between 6 mm and 12 mm bore. The connecting line shall have not less than 6 mm bore and be uninsulated metal pipe to promote rapid condensation. The line shall be vented to free it from air through the gauge cock before the gauge is fitted. If this is not convenient, a separate vent cock may be fitted as near the gauge as possible. After venting, the connecting line shall be allowed to cool so that water accumulates before opening the gauge cock.

Pressure gauges, the indication of which influences the results of the test, shall be so located that the correction for water head is nil or negligible; if this is not convenient, the gauge may be mounted above or preferably below the tapping point. In any case, the connecting line shall be as short as practicable and steps shall be taken to ensure that the line is completely filled with water.

When the gauge is above the steam pipe, a siphon tube or convolution shall be included to provide a pocket in which water can accumulate and so protect the gauge from hot steam on opening the gauge cock.

4.4.3.2 *For pressures below 250 kPa (2.5 bar), but above atmospheric pressure*

If deadweight or Bourdon gauges are used, they shall be situated below the tapping point; an uninsulated condensing vessel is to be installed close to the steam pipe having an overflow to the steam pipe in order to secure a constant level height with the correction for water head as in 4.4.7.1. Precautions given in 4.4.2.1 and 4.4.3.1 shall be taken.

If mercury manometers (see 4.1.5) are used, then an uninsulated condensing vessel shall be arranged above the tapping point to which it is connected by an insulated tube of at least 12 mm inside diameter; this tube shall slope downwards without loops or pockets to permit the condensation to drain back. The condensing vessel is connected to the mercury manometer below it by an uninsulated pipe of at least 6 mm inside diameter.

The correction for water head (to be subtracted) is the same as in 4.4.7.1.

4.4.3.3 *For pressures below atmospheric pressure*

Mercury manometers shall be situated above the tapping point and steps shall be taken to ensure that the connecting line is completely free from water.

The diameter of the pressure hole mentioned in 4.4.3 above shall be 12 mm. The connecting line shall be not less than 6 mm bore and thick walled rubber tubing is suitable as it minimizes condensation. The line shall have a continuous slope from the manometer to the tapping point to ensure free drainage. A tee piece shall be fitted in the connecting line at the manometer end to allow purging air to be drawn into the line and free it from any moisture that may be accumulating on the inner wall of the connecting pipe. The valve admitting purging air shall be absolutely tight when closed. Frequent purging will be necessary only if the slope of connecting line is not very great. If there is any danger of the mercury manometer being broken and mercury drawn into the steam pipe, then a catch pot may be fitted on the manometer end of the connecting line. No gauge cock is necessary on the manometer end of the line, but a cock shall be provided at the tapping point on the steam pipe.

4.4.4 *Shut-off valves*

A suitable shut-off valve should be installed at each pressure tapping point, and for higher pressures there should be a second valve at the gauge end of the connecting line.

4.4.5 *Calibration of pressure measuring devices*

Bourdon gauges and transducers shall be calibrated before and after the test at approximately the temperature at which they are used during the test against an accurate deadweight tester.

The accuracy of deadweight gauges shall have been checked against an accurate deadweight tester before use.

The required accuracy of a transducer should be determined by calculating the effect an error in the pressure measurement has on heat rate.

4.4.6 *Atmospheric pressure*

The atmospheric pressure to which mercury manometers or columns are referred shall, wherever practicable, be determined by means of a mercury-in-glass barometer. This barometer should be located as near as practicable at the same elevation as that of the manometers and in the same room. If this instrument is not available, the atmospheric pressure shall be determined from one or both of the following:

a) A reading taken at the time of the test from a local recognized weather bureau, corrected for the difference of elevation of the weather bureau and the turbine.

b) An aneroid or other type of barometer, provided that its accuracy and suitability are certified by a recognized authority.

The barometer shall be of the mercury-in-glass type or other type of equivalent accuracy, certified by a recognized national authority. The bore of the glass tube of the barometer shall be not less than 6 mm.

Should a reasonable doubt arise on the part of either party as to the accuracy of the barometer that is to be employed, the barometer may be compared with a barometer of the local recognized weather bureau, or equivalent, if this is satisfactory for both parties. Failing this, the barometer shall be checked by a laboratory of recognized standing by means to be agreed upon.

4.4.7 *Correction of readings*

The readings should be averaged over the test period and then corrected as follows:

All pressure-measuring devices with a head of water in the connecting line should be corrected by adding the pressure equivalent of the head of water when the gauge is above the tapping and subtracting it when the gauge is below the tapping.

A calibration correction shall be applied to those pressure-measuring devices which have been calibrated.

The pressures measured by means of liquid manometers and mercury-in-glass barometers shall be calculated in accordance with ISO 31/111 taking into account:

a) the average of readings;

b) the correction of the length of the scale on account of temperature;

c) capillarity corrections for single leg manometers, unless they have tubes of not less than 12 mm diameter;

d) density of the liquid (taking into account the liquid in the opposite leg);

e) local acceleration due to gravity, to reduce the readings to the value which would be obtained if gravity at the location of the instrument had the international standard value of 9.80665 m/s^2;

f) for liquid manometers only, the ambient pressure duly corrected;

g) difference in elevation and gravity, of tapping point and instrument, with density of the fluid.

4.4.7.1 *Corrections for the water head*

To obtain the correct pressure at the tapping point, the pressure equivalent of the head of water between the steam pipe tapping and the gauge centre line shall be added (when the gauge is above the tapping) or subtracted (when the gauge is below the tapping) from the gauge reading:

$$\Delta p = H \varrho g \qquad (10)$$

where:
H is the vertical distance between the tapping point and the centre of the pressure gauges
ϱ is the density of water at the ambient temperature
g is the local acceleration due to gravity

4.4.7.2 *Barometer reading corrections*

Barometers shall first be corrected to mercury at 273 K with appropriate allowance for the reference temperature of the scale. The reference temperature for the scale in metric countries is usually 273 K.

Barometers shall secondly need to be corrected for capillary depression of the mercury. The scale of a mercury-in-glass barometer shall be set so as to correct for this, in which case no capillarity corrections shall be applied.

Barometers are thirdly to be corrected for difference in elevation if any, between a barometer and any of the mercury pressure reading devices that are referred to it.

A fourth correction shall be made for gravity at the location of the test. Values of the various correction factors may be found in several recognized tables of standards such as those of the World Meteorological Organization, the Tables of the National Weather Bureau, the Smithsonian Tables, etc.

4.5 *Condensing turbine exhaust pressure measurement*

4.5.1 *General*

The test instrumentation should give the mean static pressure at the exhaust from each individual LP casing. It should normally consist of separate sets of pressure sensing holes, preferably connected individually or consecutively by use of suitable switching devices.

The following rules are intended to apply to all condenser arrangements. It is realised, however, that it may be easier to comply with them in respect of underslung condensers than in the case of side-mounted condensers, particularly of the integral type. Should it be found virtually impossible to comply with the Sub-clauses below, then the parties concerned should mutually agree on some alternative means of making the measurements, being guided as far as possible by the concepts herein.

4.5.2 *Plane of measurement*

Unless specified otherwise in the contract documents the condenser inlet shall be taken as the measuring plane for both turbine and condenser purposes. Modern condensers are of four general types — transverse underslung, axial underslung, separate side-mounted, integral side-mounted. For the first type the condenser inlet generally is identified with the turbine exhaust flange. For the other three types of condenser it is more difficult to identify the condenser inlet. In such cases the condenser inlet should be placed in one or more planes as close as practicable to the condenser tube nests.

4.5.3 *Pressure taps*

If the pressure distribution is unknown, the exhaust static pressure shall be measured at, or on either side of, and adjacent to, the exhaust flange, employing not fewer than one measurement for each 1.5 m^2 of exhaust conduit area. In order to limit the number of measurements, special locations of demonstrable accuracy may be used, but in no case shall there be fewer than two per exhaust annulus; it is unlikely that more than eight per exhaust annulus will be required. The pressure to be considered is the average of all of them. A discrepancy in excess of 0.3 kPa between simultaneous readings shall be cause for investigation.

For multi-exhaust turbines the instrumentation should give the mean static exhaust pressure at the condenser inlet from each individual low pressure exhaust.

For small exhaust conduits requiring not more than four gauges; where the walls are straight in the direction of flow and where the flow is likely to be uniform, all the connections may be located in the walls of the conduit. Where more than four gauges are required, some of the remaining pressure taps shall preferably be carried into the interior of the conduit, in which case the pressure holes shall be provided with guide plates arranged so that the steam flow is perpendicular to the opening. If the exhaust conduit is provided with ribs or braces traversing the steam space some of the gauge piping connections shall pass through them with the opening flush and normal to the surface of the rib. The terminals of exhaust pressure gauge connections shall be distributed over the entire exhaust conduit area and so that they will be centred, as closely as practicable in equal areas.

Gauge connections through the walls of the exhaust conduit or through ribs traversing the steam space shall be normal to and flush with the surface of the wall. The hole at the open end shall be 12 mm in diameter and uniformly rounded to a radius not exceeding 0.8 mm. The other end of the hole may be of any size suitable for pipe connection. Gauge connections in the walls of exhaust conduits, or in ribs traversing the steam space shall each be provided with a guide plate of not less than 300 mm × 300 mm, located centrally about the pressure tap, bent to conform to the curvature of the wall and located from 5 to 7 cm from the opening.

Upon agreement by the parties to the test, special pressure tips and baskets such as shown in Figure 7 and Figure 8 or equivalent devices of demonstrated accuracy may be employed in place of the flush holes, provided they are completely described in the test report.

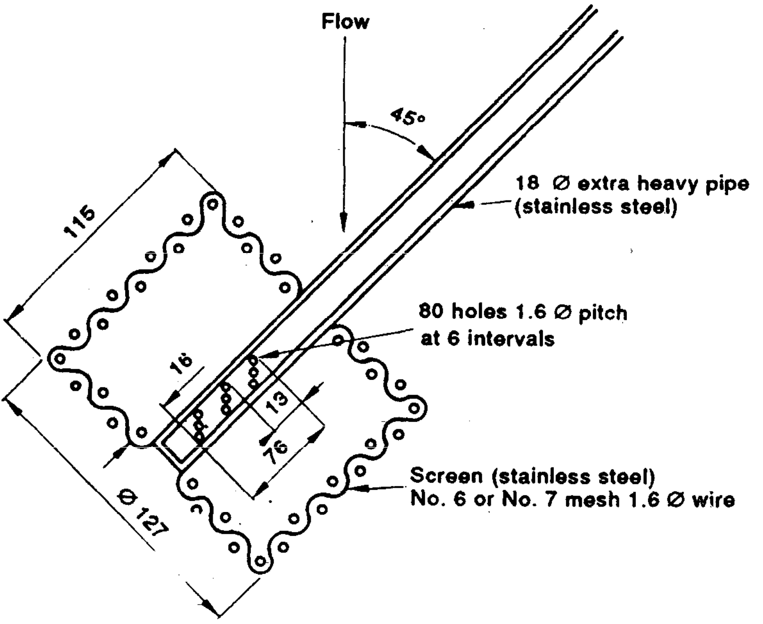

Flow
45°
18 Ø extra heavy pipe (stainless steel)
115
16
13
76
80 holes 1.6 Ø pitch at 6 intervals
Screen (stainless steel) No. 6 or No. 7 mesh 1.6 Ø wire
Ø 127
491/90

FIG. 7. — Basket tip.

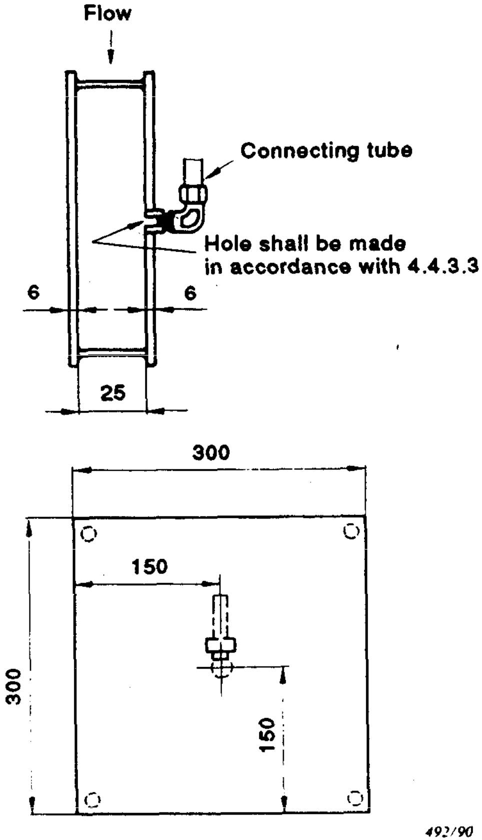


FIG. 8. — Guide plate.

4.5.4 *Manifolds*

Pressure averaging manifolds should not be used.

4.5.5 *Connecting lines*

Special precautions shall be taken in making the connections to the exhaust conduit. Each mercury manometer or column shall be mounted as near as practicable to the corresponding pressure connection in the exhaust conduit or casing, but in a position where it will be free from excessive vibration and where the observer can take readings with convenience and accuracy.

The test gauges should be at a higher level than the sensing holes so that the measuring system can be self-draining back to the condenser. Alternatively, special arrangements for adequate draining may be made. If it should prove difficult to devise a self-draining system then the parties interested in the tests should mutually agree on a means of adequately draining or purging the system by air or nitrogen flushing. Other requirements for low-pressure connecting lines appear in 4.4.3.

4.5.6 *Instruments*

All the precautions required for low-pressure measurements shall be employed. The manometer columns shall be provided with scales divided either into 0.5 mm divisions or into divisions not greater than 2.5 mm, but equipped with a vernier so that in either case the mercury head can be read with an accuracy of 0.25 mm. Prior to the tests, the scales of manometers or columns shall be calibrated so that they may be correctly read within 0.25 mm when referred to a standard.

Precautions shall be taken such that the manometer leg subject to atmospheric pressure cannot be influenced by any local atmospheric condition which would be different from those to which the barometer is subjected. Ventilating and draught fans can produce measurable differences in atmospheric pressure. There may be cases where it is necessary to pipe the atmospheric leg of the manometer or column out of doors.

Precautions should be taken to ensure that both legs of a mercury column are at the same temperature and that the mercury within a manometer column or barometer is at the same temperature as the thermometer by which the mercury head's temperature is to be measured.

The foregoing precautions should be followed in the case of low-pressure readings, the accuracies of which influence the results of the test, with the further precaution that each of these instruments, together with its corresponding thermometer, shall be set up in place, ready for reading and subject to the temperature conditions that will be obtained during the test, not less than 2 h before a test is commenced.

Increased sensitivity may be obtained by gently tapping the manometer or column tube during each observation. The glass tubing of the manometer or column shall be scrupulously clean before the mercury is introduced. Tubing may be dried by progressive rinsing with alcohol and ether and by heating.

Suitable transducers of equivalent accuracy can also be used. All of the above listed precautions, which are applicable to transducers, and further precautions pertinent to this type of instrument, shall be taken.

4.5.7 *Tightness of measuring system*

The tightness of the measuring system should be checked. When the valves adjacent to the sensing holes are closed under specified vacuum, the column reading, if mercury is being used, should not fall at a rate greater than 6mm in 5min. Rubber diaphragm type valves are more effective than cocks in keeping the system tight.

4.5.8 *Calibration*

Liquid column vacuum gauges need not be calibrated if the parties using them produce evidence to establish the accuracy of the manometric scales and can show that the purity or density of the liquid is satisfactory. Corrections for meniscus and capillarity are unnecessary if mercury manometers have 12mm bore tubes or larger.

When an absolute pressure gauge is compared with a mercury column and a barometer, errors found in excess of 0.25mm require investigation and the discrepancy shall be eliminated. If a discrepancy between a mercury column and barometer combination and an absolute pressure gauge is found to be in excess of the above limit, it shall not be assumed that the error is in the absolute pressure gauge; both it and the barometer shall be the subjects of investigation.

Transducers shall be calibrated before and after the tests. A zero reading shall be taken before and after each test run.

4.5.9 *Correction of readings*

The readings should be averaged over the test period and then corrected in accordance with 4.4.7.

Liquid column readings should be corrected in accordance with 4.4.7.

4.6 Temperature measurement

4.6.1 *Points of temperature measurement*

Temperature measurements shall be made at points as close as practicable to the points at which the corresponding pressures are measured for enthalpy determinations.

Temperatures, the values of which influence the results of the test, shall be taken at two different points close together and the mean of the two readings shall be taken as the temperature of the fluid. Should the differences exceed 0.5 K, discrepancies between the two readings should be resolved.

Should it be suspected that there are distributions of flow having different temperatures within a pipe, and the weighted average temperature influences the results of the test, the pipe is to be explored across its diameter by temperature measurement means and an average determined by a means to be agreed by the parties to the test.

4.6.2 *Instruments*

The preferred instruments for measuring relatively high temperatures are:

a) calibrated electrical resistance thermometer with a calibrated digital voltmeter or calibrated precision bridge of the 0.03% accuracy class;

b) calibrated high-grade thermocouple and precision bridge or digital voltmeter. Continuous leads to the cold junction are recommended for high measuring accuracy.

The thermocouples and resistance thermometers, and their potentiometers, bridges and galvanometers, or digital voltmeters, shall be calibrated before and after the tests.

The recalibration will generally not be necessary if individual temperature measurements are completely duplicated. All this equipment shall be carefully handled and maintained and shall be periodically checked for uniformity and stability.

Mercury-in-glass thermometers are recommended for use when the temperature to be measured is less than 373 K, and the locations are such that readings may be taken without difficulty.

Mercury-in-glass thermometers used to measure temperatures which influence the results of the test shall be of the solid-stem precision type with etched scale plate graduated with scales suitable for the measurement to be made. Commercial or industrial metal-encased thermometers shall not be used.

4.6.3 *Main temperature measurements*

The main temperatures are those which have a direct influence on the acceptance test result such as initial steam, hot and cold reheat steam, final feed water temperature, and cooling water temperatures (see 4.6.5).

Other temperatures, such as feed water pump inlet temperatures and discharge and deaerator condensate inlet temperatures, may also be main temperatures if the feed heating system is not included in the turbine contract and according to the method of determining the primary flow.

If the fluid flows associated with the main temperature measurements are conveyed in multiple pipes, each main temperature should be taken as the arithmetic mean of the individual temperatures unless the parties interested in the test agree that some flow weighting is appropriate.

Two thermometer wells should be provided in each pipe to permit the temperature measurement to be independently duplicated. Each pipe temperature should be taken as the arithmetic average of the two measurements unless the parties interested in the test agree otherwise.

The final feed temperature measurement should be taken after the junctions of any heater by-passes, and sufficiently far downstream to ensure that adequate mixing has occurred.

4.6.4 *Feed train temperature measurements (including bled steam)*

With the exception of main temperature measurements, the feed train temperature measurements need not be duplicated. Sufficient inlet and outlet temperatures on each heater should be measured to enable a heat balance to be calculated.

In many instances, the inlet feed temperature of one heater would be the same as the outlet feed temperature of the preceding heater* and, in these instances, one temperature measurement to serve both heaters would be sufficient. If both the feed inlet temperature and the preceding feed outlet temperature are measured, then a mean of the two should be taken to obviate discrepancies in the heat balance. Where a return connection exists between the two points, measurements should be made upstream and downstream of the junction.

Steam temperatures should be measured at each end of the bled steam pipes: near the turbine connection upstream of the non-return valve and near the feedwater inlet connection.

If mixing occurs in a bled steam pipe, the temperature of the mixture should be taken sufficiently far downstream of the junction to ensure that adequate mixing has occurred.

Thermowells should be located in areas which assure good mixing and have minimum possibility of stratification

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* The temperature is taken at least 10diameters downstream from the heater outlet to ensure adequate mixing.

4.6.5 *Condenser cooling water temperature measurement*

These temperatures are normally only required if condenser performance is included in the turbine generator performance guarantee.

a) Inlet temperature

Inlet temperature is generally constant across the section of the pipe, and unless there is reason to suspect that stratification is occurring one temperature measurement in each inlet pipe will suffice. Thermometer pockets may be used or, alternatively, a continuous flow of sample water may be drawn off through a chamber into which is inserted a direct contact thermometer. If either party suspects stratification, the measurement shall be by one or both of the methods used for outlet temperature as described in the following paragraph.

b) Outlet temperature

Temperature stratification occurs in the cooling water discharge boxes. To permit mixing to occur, the measuring positions should be several diameters downstream. Temperature sampling probes should be used at each condenser outlet, on at least two diameters. The probes may be either perforated sampling tubes through which water can be drawn off to a mixing chamber or they may be thermopiles to obtain a mean temperature in situ. There shall be not less than one sampling hole or thermocouple for each $0.2\,m^2$ of pipe area and they should be situated at centres of equal areas.

4.6.6 *Accuracy of temperature measuring equipment*

The temperature measuring equipment shall be of such accuracy that the individual maximum errors do not influence the final test result by more than 0.05%.

4.6.7 *Thermometer wells*

The material of a thermometer well shall be suitable for the temperature to be measured. Tubes and wells shall be as thin as practicable, consistent with safe stress, the inner diameters being as small as practicable. It is important that the wells be clean and free from corrosion or oxide. Wells for high or main temperature measurements may be provided with external fins for good heat absorption. With high pressures and high temperatures, it is advisable to weld the thermometer wells to the pipe.

Thermometer wells shall preferably be dry, especially for the higher temperature measurements but shall be carefully covered and sealed with material to reduce air circulation or loss of heat.

If temperature rise across the feed pump has to be measured, the thermometer pockets at inlet and discharge shall be of duplicate type and material. The pocket in the discharge piping shall be located sufficiently downstream of the pump to permit a good mixing of the flow.

4.6.8 *Precautions to be observed in the measurement of temperature*

The following precautions shall be observed in the measurement of the temperature:

a) Heat that is transmitted by conduction or radiation to or from the temperature measuring means, other than from the medium being measured, shall be reduced to a minimum.

b) The immediate vicinity of the point of insertion and the projecting parts of the well and its support shall be thermally insulated.

c) In pipes of less than 75 mm internal diameter, the thermometer shall be arranged axially in the pipe by inserting it in an elbow or tee. At any location where an elbow or tee is not available, the piping shall be modified accordingly.

In pipes having an internal diameter greater than or equal to 75 mm, the sensitive element shall be located between the centre and a point 25 mm radially beyond, except that in the case of very large pipes and special multi-point measuring devices, no well need exceed a length of 150 mm inside a pipe.

d) In measuring the temperature of flowing fluids the heat-receiving part of the apparatus shall not be in a dead space.

e) In taking readings, a mercury-in-glass thermometer shall not be raised in the thermometer well further than is necessary to render visible the top of the mercury thread. Other types of instrument shall not be moved while readings are being taken.

f) Each complete temperature measuring installation shall be set up in place in full working condition at the temperature conditions that will prevail during the test, for not less than 2 h before a test is commenced.

4.7 *Steam quality measurement*

4.7.1 *General*

In power stations employing certain types of nuclear reactor the steam supplied to the turbines is at saturation temperature and may contain a small percentage of moisture. It is therefore necessary to ascertain the moisture content in order to determine the enthalpy of the initial steam.

It may also be required to determine the moisture content of the steam after partial expansion in the turbine, for example at a point where extracted steam is taken to a feedwater heater or a water-separator or reheater. Where it is practicable to condense the extracted steam and measure the condensate, the enthalpy of the steam can be determined by a heat balance calculation.

The usual methods of determining the moisture content of steam are by means of:

- a throttling calorimeter,
- an electrical heating calorimeter.

The former is only applicable when the quality and the pressure of the steam are sufficient to produce a measurable degree of superheat in the calorimeter. The latter is not subject to these limitations. Both methods, however, are liable to give misleading results because of the probable lack of homogeneity, and the difficulty of obtaining a correct sample of the local steam-water mixture. Consequently, there is uncertainty as to whether the steam passing to the calorimeter is representative of the main steam flow.

Recently, more precise methods employing radioactive or non-radioactive tracers have been introduced and established.

4.7.2 *Tracer technique*

The tracer technique employing the dilution method is an accurate method for determining either the water phase or the moisture fraction of a two-phase vapour-water flow. The dilution method is based on the measurement of a tracer concentration in a water sample. Dilution can be accomplished in either of two ways, applicable to determining both throttle and extraction enthalpy.

Condensing method: It is assumed that the tracer concentration in the moisture carried by the steam is the same as that in the water in the boiler. After condensation of the vapour and measurement of the mass flow and of the tracer concentration in the boiler and in the condensate, a mass balance calculation enables the amount of water transported in the steam from the boiler to be determined.

Constant rate injection method: A solution of tracer of known strength is injected at a known rate into the steam flow. After mixing, a sample of the water is drawn off and the tracer concentration measured. A balance calculation enables the moisture content of the steam upstream of the injection point to be determined. Precautions shall be taken to ensure that the mixture is homogeneous and that no steam is withdrawn with the water.

Methods other than these may be used upon agreement.

4.7.3 *Condensing method*

An appropriate tracer, dissolved in the water phase of wet steam at a concentration C_{wat} will be diluted by condensation of vapour. After the steam is totally condensed, the tracer concentration in the condensate will be C_{cond}. The concentrations are related by the equation:

$$C_{wat} \cdot \dot{m} = C_{cond} \cdot \dot{m}_{cond} \tag{11}$$

where:

$\dot{m}$ is the mass flow rate of water in wet steam flow

$\dot{m}_{cond}$ is the mass flow rate of condensate from wet steam

With the tracer concentrations known from test measurements, before and after condensation, steam wetness fraction (moisture) is represented by the ratio:

$$1 - x = \frac{\dot{m}}{\dot{m}_{cond}} = \frac{C_{cond}}{C_{wat}} \tag{12}$$

and the steam quality is determined by:

$$x = 1 - \frac{C_{cond}}{C_{wat}} \tag{13}$$

Throttle quality can be calculated from the quality and pressure of steam leaving the steam generator, and throttle pressure.

The moisture in the steam leaving the steam generator is the result of water carry-over. Thus, a tracer present in the steam generator water will also be found in the steam.

In non-reheat cycles, the tracer will finally be diluted in the total flow going back to the steam generator. By the application of the condensing method, steam generator exit moisture can be evaluated using equation (13) above.

In the case of reheat cycles, the error in the throttle moisture determination caused by plating out of the tracer in the reheaters is negligible, provided that the external moisture separator effectiveness is approximately 100%. However, there is the possibility of measuring the moisture carry-over of the steam generator during special tests with the reheaters out of service if agreed between the parties concerned.

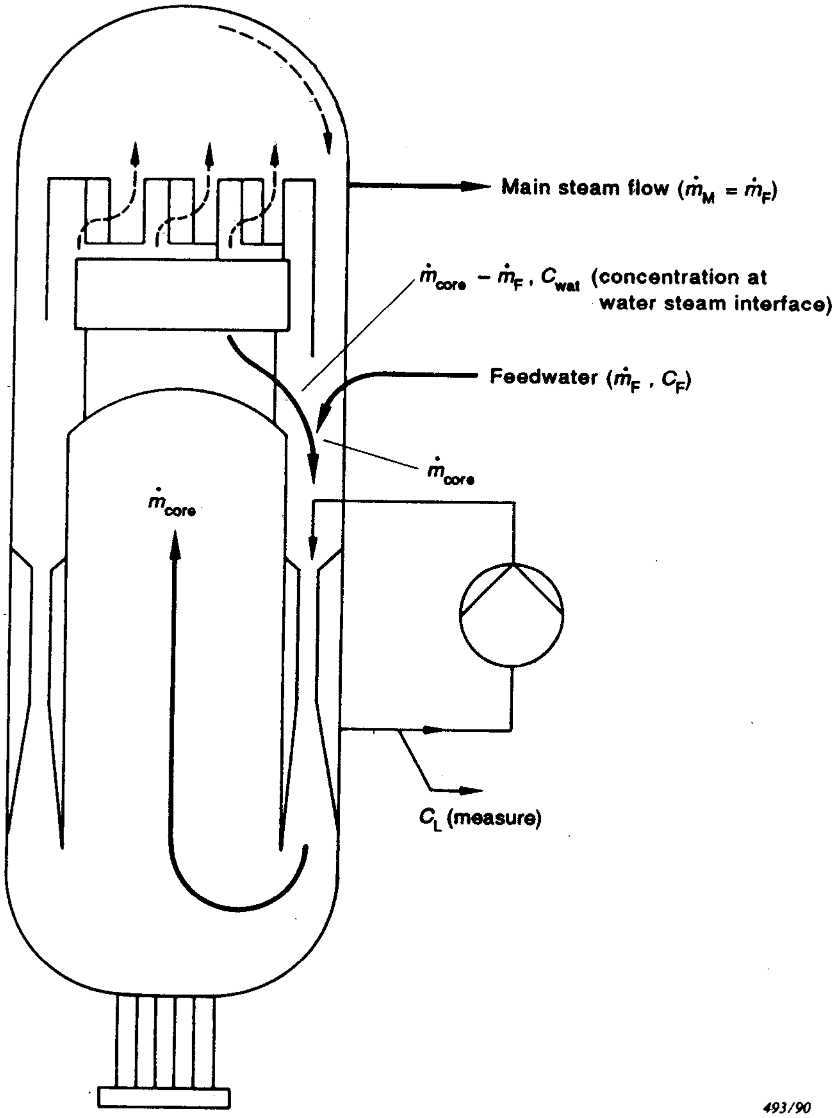
When the tracer concentration is measured at the bottom of the steam generator, the factor R (see Figures 9 and 10) has to be taken into account in the determination of the concentration C_{wat} which serves for the determination of the steam quality. Consequently, this procedure is less precise than the direct measurement of C_{wat}.

Determination of the concentration in the total flow C_{cond} depends on the arrangement of the feedwater heaters. On cycles with cascading heaters, total flow usually exists at the discharge of the condensate pumps. On other cycles, if the demineralizers are bypassed during the test, C_{cond} will be the tracer concentration in the final feedwater. Another possibility is to calculate C_{cond} from a tracer flow balance. However, this calculation requires several flow and concentration measurements. In all cases, effects such as external tracer sources feeding into the cycle or losses of tracer (demineralizers) shall be taken into account.

The condensation method may also be used to determine wet extraction steam enthalpy. This method is particularly attractive if a suitable tracer is already present in the steam path. However, error analysis shows that accurate results can only be obtained on heaters without cascading drains.

With this method, extraction enthalpy is evaluated from an energy balance and a tracer balance around the heaters.

For the tracer balance, the concentration of the tracer in all flows to and from each heater shell side are needed. Sampling the heater drains for concentration measurement of the tracer is fairly easy, as this is only single phase flow. Sampling water out of the extraction line requires the same precautions as in the case of the injection method.


Main steam flow ($\dot{m}_M = \dot{m}_F$)
$\dot{m}_{core} - \dot{m}_F$, C_{wat} (concentration at water steam interface)
Feedwater ($\dot{m}_F$, C_F)
$\dot{m}_{core}$
$\dot{m}_{core}$
C_L (measure)
493/90

$$\dot{m}_M = \dot{m}_F$$

$$C_{wat}(\dot{m}_{core} - \dot{m}_F) + \dot{m}_F C_F = \dot{m}_{core} C_L \tag{14}$$

$$C_{wat} = \frac{\dot{m}_{core} C_L - \dot{m}_F C_F}{\dot{m}_{core} - \dot{m}_F} \tag{15}$$

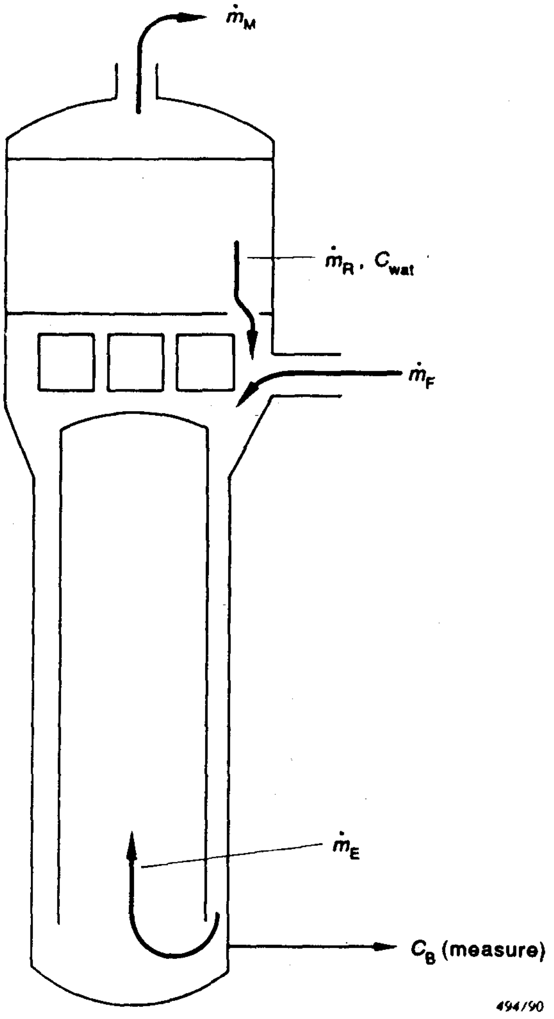
$$C_F < C_L \text{ and } \dot{m}_F < \dot{m}_{core}$$

$$C_{wat} = C_L \frac{\dot{m}_{core}}{\dot{m}_{core} - \dot{m}_F} = \frac{C_L}{1 - R} \tag{16}$$

where:

$$R = \frac{\dot{m}_F}{\dot{m}_{core}} = \frac{\dot{m}_M}{\dot{m}_{core}}$$

FIG. 9. — Throttle steam quality calculations for boiling water reactor.



C_{wat} = tracer concentration at water-steam interface

C_B = blowdown tracer concentration

$\dot{m}_E = \dot{m}_R + \dot{m}_M$

$R = \dfrac{\dot{m}_M}{\dot{m}_E}$ or $\dot{m}_E = \dfrac{\dot{m}_M}{R}$

$$\dot{m}_R = \dot{m}_E - \dot{m}_M = \frac{\dot{m}_M}{R} - \dot{m}_M = (1 - R)\frac{\dot{m}_M}{R} \tag{17}$$

$$C_{wat} \approx \frac{C_B \dot{m}_E}{\dot{m}_R} = \frac{C_B\left(\dfrac{\dot{m}_M}{R}\right)}{(1 - R)\dfrac{\dot{m}_M}{R}} = \frac{C_B}{1 - R} \tag{18}$$

$$C_{wat} = \frac{C_B}{1 - R} \tag{19}$$

FIG. 10. — Throttle steam quality calculations for pressurized water reactor.

4.7.4 *Constant rate injection method*

A water-soluble tracer of concentration C_{inj} is injected at a constant rate, $\dot{m}_{inj}$, into the vapour-water flow where moisture is to be measured. The concentration C_{wat} is measured in the water phase downstream of the injection point after adequate mixing has taken place. For this condition the following material balance can be written:

$$C_o \cdot \dot{m} + \dot{m}_{inj} \cdot C_{inj} = (\dot{m} + \dot{m}_{inj} + \Delta\dot{m}) \cdot C_{wat} \tag{20}$$

or

$$\dot{m} = \frac{\dot{m}_{inj} \cdot (C_{inj} - C_{wat}) - \Delta\dot{m} \cdot C_{wat}}{C_{wat} - C_o} \tag{21}$$

where:

$\dot{m}$ is the mass flow rate of water in vapour-water mixture at the sampling point

C_o is the initial concentration in the water phase at the sampling point, before injection starts, due to natural amounts of tracer (background concentration)

$\Delta\dot{m}$ is the change in water flow (condensation of vapour due to injection of the cold tracer solution)

Normally $C_{wat} < C_{inj}$, $C_o < C_{wat}$ and $\Delta\dot{m} < \dot{m}$, so that the equation (20) is reduced to:

$$\dot{m} = \dot{m}_{inj} \cdot \frac{C_{inj}}{C_{wat}} \tag{22}$$

4.7.5 *Extraction enthalpy determined by constant rate injection method*

If the flow rate of the water phase in the extraction line to a feedwater heater is known, wet steam enthalpy can be calculated by energy balance around the heater.

The water flow rate can be measured with the constant rate injection method. Measuring flow rate and concentration of the tracer solution and maintaining a constant injection rate is comparatively simple. However, the tracer concentration in the water phase downstream of the point of injection can be accurately determined only if the tracer is well mixed and a sample of the liquid phase can be obtained.

4.7.5.1 *Injection points*

For the sample to be truly representative, the tracer shall be uniformly distributed in the water phase. The injection point should, therefore, be located immediately downstream of the extraction flange of the turbine, and the sampling point should be close to the heater. A long run of pipe with several elbows will promote mixing. Use of a spray for injecting would be beneficial, but it may not be necessary.

4.7.5.2 *Sampling points*

Since any condensed vapour in the sample will falsify the result, care shall be taken in selecting the location of the sampling tap. At the conditions and velocities normally found in extraction lines, the water is not uniformly distributed over the cross-section but agglomerated towards the pipe wall. This is favourable for water sampling, so that a simple wall tap should prove satisfactory. However, advantage should be taken of gravitational or centrifugal forces by locating the tap on the bottom of the pipe or on the outside at the exit of an elbow. Figure 11 shows a typical installation of injection and sampling points. In cases where the extraction line is very short, such as heaters installed in condenser necks, problems may be encountered in obtaining water samples. In such cases, these rules recommend that the water sample be taken from the heater drain.

In cycles with pumped ahead drains the above method yields accuracy equal to the injection method without any additional instrumentation. In cycles with drains cascading to the condenser, the upstream drains shall be diverted directly to the condenser so as to yield comparable results. Such diversion necessitates designing such drain piping to the condenser to accommodate total cascade flow at full load. The diversion method should be employed prior to the heat rate test.

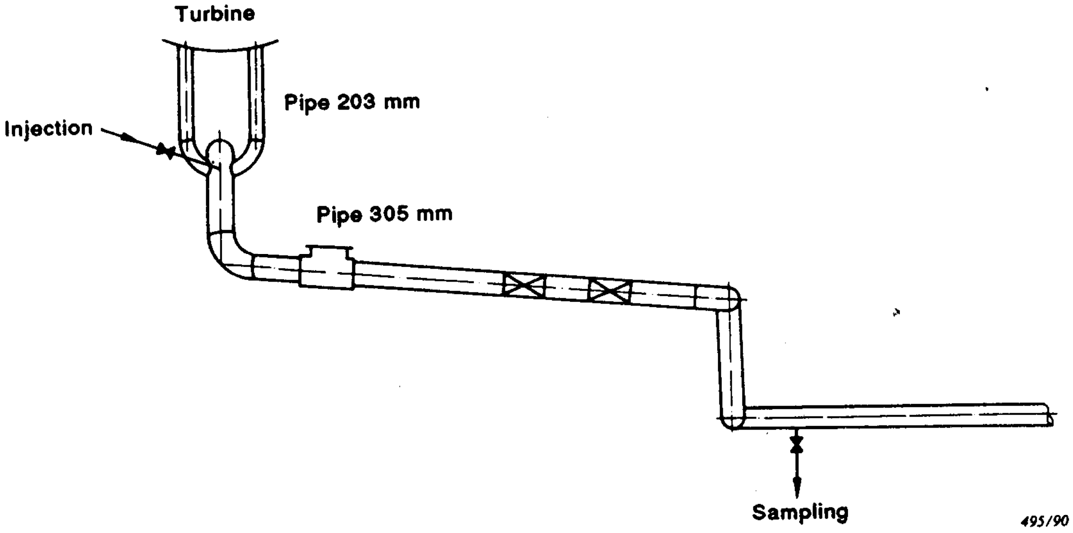


FIG. 11. — Typical installation of injection and sampling points.

4.7.5.3 *Sampling flow rates*

The sampling flow rate shall be adjusted so that entrainment and subsequent condensation of vapour is prevented. The maximum allowable sampling rate can be determined, for example, by analysing the sampling stream for dissolved oxygen. Oxygen (20 to 30 ppm) is naturally present in the steam from boiling water reactors as a result of radiolysis. The sampling flow rate shall be determined prior to the heat rate test. The oxygen content shall be measured for various sample flow rates and plotted as shown in Figure 12. The flow rate at which steam starts to entrain in the sampling is evidenced by a sharp rise in oxygen content. The validity of using oxygen or other suitable tracer as a means of tracing the vapour fraction is based on the distribution of oxygen between the liquid and vapour phases. At pressures less than 35 bar, oxygen is almost entirely in the vapour phase.

In other types of plants, a suitable tracer, such as xenon 133, could be added.

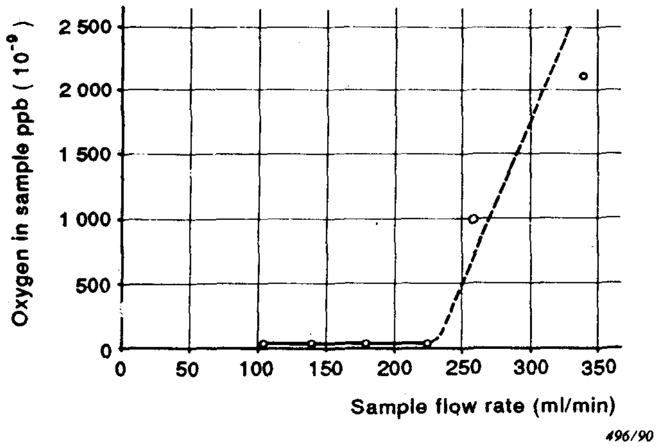


FIG. 12. — Oxygen content of sample stream.

4.7.6 *Tracers and their use*

For condensing and constant-rate injection methods to give accurate results, tracers shall meet the following criteria:

a) No hazard to operating personnel.

b) No harmful effects on materials employed.

c) Soluble in water, but essentially insoluble in steam (concentration in the steam phase of 10^{-6} can be attained with suitable tracer compounds).

d) Non-volatile.

e) Stable at the conditions existing in the turbine cycle, and not absorbed on internal surfaces (provided that the water is not evaporated completely).

f) Mixed completely and uniformly with all the water available at any instant.

Light water reactors of the present generation are designed for pressure and temperature levels which permit a number of tracers to meet these criteria. At higher pressure levels this may be more difficult. Furthermore, the problem of chemical contamination, which is tied together with the sensitivity and accuracy of the analytical methods available, has to be considered. Methods such as measurement of conductivity or the gravimetric methods may be too insensitive to produce the required accuracy at the concentration levels which can be tolerated in some nuclear systems. Care shall be taken to prevent environmental contamination when tracers are used.

4.7.6.1 *Radioactive tracers*

Radioactive tracers are particularly attractive for application in nuclear power plants, where licensing required for possession and handling of radioactive materials presents no particular problem. Tracer concentrations of less than 1 in 10^9 can be accurately measured using gamma counting techniques. For steam cycles with very low radioactive background, the tracer activity concentration required for accurate testing is very small; however, the tracer should be a short-lived isotope to eliminate long term contamination problems. Since it is not practicable to measure the concentration of recovered samples simultaneously it will be necessary to apply a correction to the measured concentration of each sample to account for isotope decay. One of the tracers which meets these criteria is 15h sodium-24. If the tracer technique is used to determine throttle and extraction steam quality and heater leakage there is some advantage in using three different radioactive tracers.

4.7.6.2 *Non-radioactive tracers*

A number of tracers are available. The sodium tracer technique is based on accurate and direct determination of the mass concentration of sodium in water samples. Sodium may be present in PWR cycles due to the use of sodium phosphates for secondary loop water control. The sodium tracer technique also preserves the non-radioactive status of the secondary loop in PWR cycles.

a) Flame photometry method
Sodium analysis may be performed with a flame spectrophotometer. Care shall be taken to prevent environmental sodium from contaminating a sample. Multiple determinations of sodium concentrations shall be made for each sampling point. Sodium concentration may also be determined from a continuously flowing sample.

b) Sodium ion electrode method
The sodium analyzer may be used for continuous monitoring of a flowing sample, as well as for analyzing separate samples.

The application of non-radioactive tracer techniques shall be consistent with regulations concerning the metallurgical safety of the reactor system and all other related equipment. Lithium salts may also be used in preference to sodium.

4.8 *Time measurement*

The time of test periods and observations may be determined by:

a) signals from a master clock or timekeeper;

b) observations of watches, which are to be synchronized before the test, by the individual observers.

A time measurement of high accuracy is necessary for each measurement employing an integrating meter. Individual stop watches or electric time measuring devices shall be employed. Special care shall be given to the accurate synchronization of the readings of the integrating meter and the time measuring devices.

4.9 *Speed measurement*

Speed can be measured by means of a counting mechanism and clock, a stroboscope, a frequency measuring instrument (mechanical or electrical) or a speed measuring instrument. Signal transducers and signal transformers are also accepted.

5. Evaluation of tests

5.1 *Preparation of evaluation*

From the instrument readings taken during the test, the test results according to 2.4 are calculated.

Prior to evaluating the measurements, a time interval shall be selected from the overall period during which readings for a test have been taken, equivalent to at least the period laid down in 3.8.3. During this test period the provisions of 3.8.1 and 3.8.2 relating to the deviations of the operating conditions from the guarantee conditions and relating to the fluctuations in the operating conditions shall be satisfied.

Readings of all instruments, including integrating instruments, and corresponding time measurements shall be available for the start and the end of the selected test period (see 5.2.1).

5.2. *Computation of results*

5.2.1 *Calculation of average values of instrument readings*

For further evaluation, the average value of the readings taken during the test period defined according to 5.1 is calculated for each measuring instrument.

For variables which influence the evaluation in a linear manner, the average value is the arithmetic mean value. The theoretically correct procedure for averaging the readings of a pressure difference across a flow-measuring device is to calculate the arithmetic mean value of the square roots of the readings. However, if the amplitude of readings is less than 10%, the maximum possible error introduced by not calculating the square root of the arithmetic mean of the readings is less than 0.1%.

If data from integrating instruments are compared with averaged readings of indicating instruments, it is important to ensure that they have been determined for the same time period. The first and last readings of the indicating instrument should then carry only half the weight in the averaging procedure.

5.2.2 *Correction and conversion of averaged readings*

The averaged readings are corrected to take care of all influences resulting from the instrumentation and converted to the necessary units considering:

a) instrument constants and zero corrections;

b) calibration corrections;

c) reference values of instrument readings (e.g. barometric pressure, ambient temperature);

d) any additional influences (e.g. water legs).

5.2.3 *Checking of measured data*

5.2.3.1 *Compatibility*

After computation of the measured data, such as pressures, temperatures and flow rates, a thorough examination shall be made for serious errors, inconsistencies with the laws of physics and general compatibility. If major discrepancies are detected, the cause and extent of which are unknown, the test run shall be repeated completely or to the necessary extent. Appropriate additional measurements shall be made for clarification. Instrument readings which are obviously incorrect shall be eliminated. Subject to mutual agreement of the parties interested in the test, such readings may be replaced by other instrument readings or by appropriate calculated or estimated values.

5.2.3.2 *Evaluation of multiple measurements*

Where results from several independent instruments are available for the same variable, an average value of these shall be calculated in a suitable manner, normally as the arithmetic mean value.

5.2.3.3 *Initial steam flow value*

If the compatibility conditions according to 4.3.3 are met the arithmetic mean of the initial steam flow values determined from different primary flow measurements is used in the further computation. Otherwise 4.3.3 is applied.

5.2.3.4 *Leakages*

Leakages shall, as far as is practicable, be identified and eliminated before the test. If any identified leakages cannot be eliminated, their flow rates shall be measured or estimated. These estimates shall be included in the main or secondary flow rate calculations. Unidentified leakages, which result in a loss of working fluid, shall also have their flow rate(s) and position(s) estimated and included, if considered necessary, in the main or secondary flow rate calculations.

The total leakage unaccounted for during the test, expressed as a percentage of full load initial steam flow, shall not exceed 0.1 %; otherwise the test can be accepted only by mutual agreement of the parties in the test.

5.2.4 *Thermodynamic properties of steam and water*

The steam and water tables and charts upon which the guarantees are based shall be used for the calculation of the test results. The name and edition of the tables and charts employed shall be stated in the report of the tests. The tables used shall be consistent with the International Skeleton Tables established at the Sixth International Conference on the Properties of Steam (ICPS) in 1963, and preferably be based on the 1967 IFC Formulation for Industrial Use that was approved at the Seventh ICPS in 1968 or on the latest edition.

5.2.5 *Calculation of test results*

The thermal and/or thermodynamic efficiency, the initial steam flow capacity and the output have to be calculated in accordance with the definition of the guarantee values (see 2.4).

In accordance with 5.1 and 5.2 a definite value shall be established for each variable which shall be used exclusively in further evaluation.

6. Correction of test results and comparison with guarantee

6.1 *Guarantee values and guarantee conditions*

The guarantee values to be verified by the thermal acceptance tests indicate the level of the turbine performance. Their definitions are given in 2.4.

Since the test results depend decisively also on cycle terminal parameters and conditions and on the parameters of the feed-heating system, all these have to be defined completely and clearly and they form the specified guarantee conditions. They are part of the guarantees. In many cases it is recommended that these data be given in the form of complete heat-balance diagrams with all pertinent data.

If extraction or addition of steam and/or water is already included in the guarantee cycle, it is an additional specified guarantee condition.

6.2 *Correction of initial steam flow capacity*

For correction of the initial steam flow capacity to guarantee conditions the following equation is applied:

$$\dot{m}_{\mathrm{l,\,max,\,c}} = \dot{m}_{\mathrm{l,\,max,\,m}} \cdot \frac{P_{\mathrm{l,\,g}}}{P_{\mathrm{l,\,m}}} \sqrt{\frac{P_{\mathrm{l,\,m}} \cdot v_{\mathrm{l,\,m}}}{P_{\mathrm{l,\,g}} \cdot v_{\mathrm{l,\,g}}}} \qquad (23)$$

where:

$\dot{m}_{\mathrm{l,\,max,\,m}}$ is the initial steam flow capacity measured during test with valves wide open

If the ratio of exhaust pressure to inlet pressure of the turbine is not sufficiently small, the use of the complete equation may be necessary:

$$\dot{m}_{1,\max,c} = \dot{m}_{1,\max,m} \cdot \frac{P_{1,g}}{P_{1,m}} \sqrt{\frac{P_{1,m} \cdot v_{1,m}}{P_{1,g} \cdot v_{1,g}}} \sqrt{\frac{1 - \left(\frac{P_{2,g}}{P_{1,g}}\right)^2}{1 - \left(\frac{P_{2,m}}{P_{1,m}}\right)^2}} \qquad (24)$$

The exponents 2 of the pressure ratios are approximations of the exact value

$$\frac{1 + k}{k}.$$

6.3. *Correction of maximum output*

In the correction of the maximum output $P_{\max}$ to guarantee conditions, all the operating conditions influencing the initial steam flow, the enthalpy drop and its distribution in the different parts of the turbine and the efficiency values in the different parts of the turbine should be taken into account.

Corrections for all these parameters (particularly live steam conditions, reheat temperature and condenser pressure) can be made with appropriate correction curves.

A complete correction can be made by appropriate recalculation of the thermal cycle.

An approximate correction formula assuming similar distribution of enthalpy drop and efficiency is:

$$P_{\max,c} = P_{\max,m} \cdot \frac{\dot{m}_{1,\max,c}}{\dot{m}_{1,\max,m}} \cdot \frac{\eta_{\max,c}}{\eta_{\max,m}} \qquad (25)$$

For the determination $\dot{m}_{1,\max,c}$ see 6.2. The efficiency to be used shall be, according to the formulation of the guarantees, the thermal efficiency η_t or the thermodynamic efficiency η_{td}.

6.4 *Correction of thermal and thermodynamic efficiency*

If any operating conditions, according to 6.1, differ during the test from the guarantee conditions, the thermal or thermodynamic efficiency, or heat rate or steam rate have to be corrected before they can be compared with the guarantee values. In order to keep the correction small, the operating conditions during the test shall be as close as practicable to the specified guarantee conditions. The maximum permissible deviations for the most important operating parameters are stated in 3.8.2.

The correction for deviations from specified guarantee conditions can be divided into three categories.

Category 1 comprises corrections for deviations of the terminal operating conditions of the turbine itself from specified guarantee conditions, such as (see also 6.7):

a) initial steam pressure,

b) initial steam temperature,

c) reheat steam temperature,

d) initial steam quality,

e) reheater pressure drop,

f) turbine-exhaust pressure or condenser cooling water temperature and flow,

g) moisture-separator effectiveness, if not supplied with the turbine,

h) speed.

Category 2 comprises variables which primarily affect the feed-heating system. This category includes corrections, such as the following (see also 6.7):

a) feed-heater terminal differences,

b) extraction-line pressure drops,

c) system water-storage changes and make-up flow,

d) enthalpy rise through condensate and feed-pumps,

e) condensate undercooling in condenser,

f) spray-attemperator flows for boiler,

g) different configuration of feed-heating system (for example, heater out of service).

Category 3 corrections concern the generator operating conditions. They are independent of the remainder of the plant and simple to determine. If, however, the heat equivalent of the generator losses is transferred into the feed-water, they are of greater consequence and most conveniently treated in Category 2:

a) generator power factor,

b) voltage,

c) hydrogen pressure.

6.5 *Definition and application of correction values*

For correction purposes it is normally assumed that the influences of the various operating parameters on the test result are mutually independent of each other. Therefore, the correction values are determined individually according to the deviations of the individual operating parameters and are then combined to form a total correction.

Correction values are factors defined as follows:

$$F = \frac{\eta_c}{\eta_m} \tag{26}$$

where:

η_c is the corrected efficiency based on specified guarantee conditions
η_m is the measured efficiency

The individual correction factors F_1, F_2, F_3... are then combined to give a total correction factor F_{tot}.

$$F_{tot} = F_1 \cdot F_2 \cdot F_3 \ldots$$

The corrected efficiency value is then:

$$\eta_c = \eta_m \cdot F_{tot} \tag{27}$$

For all parameters, where the correction is load dependent, correction factors have to be determined for each guarantee load point.

The correction of the test result to specified guarantee conditions can also be effected by a complete recalculation of the turbine and its thermal cycle, usually by means of a computer program with due consideration of the characteristics of the turbine and plant components and the operating conditions during the test. This method yields a complete correction directly without the use of individual correction factors and also takes into account to a large extent the interdependence of the different variables.

It may also be convenient to make only the corrections of category 2 by recalculation, since correction curves for these variables may not be readily available. The category 1 corrections are then made by means of correction curves.

6.6 *Correction methods*

The determination of the correction method and of the necessary values and curves depends on the method to be applied for the guarantee comparison (see 6.8).

a) If the guarantee comparison is made for constant initial steam flow, for each variable its influence on the thermal or thermodynamic efficiency has to be considered for the correction.

b) If the guarantee comparison is made for constant valve position of the turbine, the influence on both efficiency and output of each variable has to be determined.

The correction and comparison procedure to be applied should be agreed upon by the parties interested in the test sufficiently early before the test to allow the necessary preparatory work to be completed. The manufacturer's correction curves should be supplied within an agreed period (unless special agreements have been made in the contract, approximately three months before the test).

The correction method of 6.6.1 is recommended, in particular, for turbines with complicated cycles (turbines with steam extraction or bleeding for other purposes, with secondary steam entry. etc., or with complex feed-water heating cycles) and for turbines with many cycle corrections. If suitable means of calculation are applied, this method gives corrections which are more exact, complete and useful than the corrections according to the method described in 6.6.2. Other suitable correction methods may also be applied by agreement.

6.6.1 *Correction by heat balance calculation*

The correction may be made by calculating a heat balance to correct the test cycle and the test operating conditions to the guarantee cycle and guarantee operating conditions. That is, the turbine test efficiencies may be corrected to the specified conditions (for the influence of operating conditions, if necessary). These corrected test efficiencies may be used to calculate a "corrected test" cycle which can be compared with the guarantee cycle.

Alternatively, the correction may be made by calculating a heat balance to correct the guarantee cycle and the guarantee operating conditions to the test cycle and test operating conditions. The turbine guarantee efficiency may be corrected according to the test conditions (for the influence of operating conditions, if necessary). This corrected test efficiency may be used to calculate a "corrected guarantee" cycle which can be compared with the test cycle.

For turbines using superheated steam, the first method is usually applied, whereas for turbines using wet steam the second method may be easier to perform correctly.

For the correction by recalculation of a complete heat balance under test conditions, a calculating method (program) is necessary. This correctly takes into account the influence of the test conditions on the performance of the turbine and the plant components.

If the program which had been used for the calculation of the contract guarantee cycle cannot be used the following method can be applied:

First, a thermal efficiency value at guarantee conditions η'_g is determined with the available program, which may deviate slightly from the guaranteed efficiency η_g because of minor differences between the programs and data used for the determination of the guarantee values and for the recalculation. Then a thermal efficiency η'_m under test conditions is calculated with the same program and the same performance characteristics of turbine and plant components.

The measured thermal efficiency corrected for test conditions η_c is then:

$$\eta_c = \eta_m \frac{\eta'_g}{\eta'_m} \tag{28}$$

The correction by calculation may be limited to the variables of Category 2, the correction for variables of Categories 1 and 3 are made by use of correction curves. If the recalculation of the cycle for the Category 2 corrections has already caused a change in value of a variable causing Categories 1 or 3 to be corrected, only the remaining difference to guarantee condition may be corrected with the curve.

Both principles described in 6.6 may be applied for correction by heat balance calculation. The method of guarantee comparison is to be chosen accordingly (see 6.8).

All necessary data and calculation methods shall be made available to the parties to the test sufficiently early before the acceptance test.

6.6.2 *Correction by use of correction curves prepared by the manufacturer*

For case 6.6*a)* the correction curves gives values of the correction factor F_η for the efficiency as a function of the different variables. For case 6.6*b)*, curves for the correction factors F^*_η for the efficiency, different from those for case 6.6*a)* and for the correction factors F^*_p for the output, as a function of the different variables, are necessary.

If a correction factor depends also on initial steam flow (case 6.6*a)*), or output (case 6.6*b)*), several correction curves for different loads, preferably for the guarantee loads, are necessary.

It shall be clearly indicated, on the correction curves, the method described in 6.6 for which they have been prepared and have to be applied.

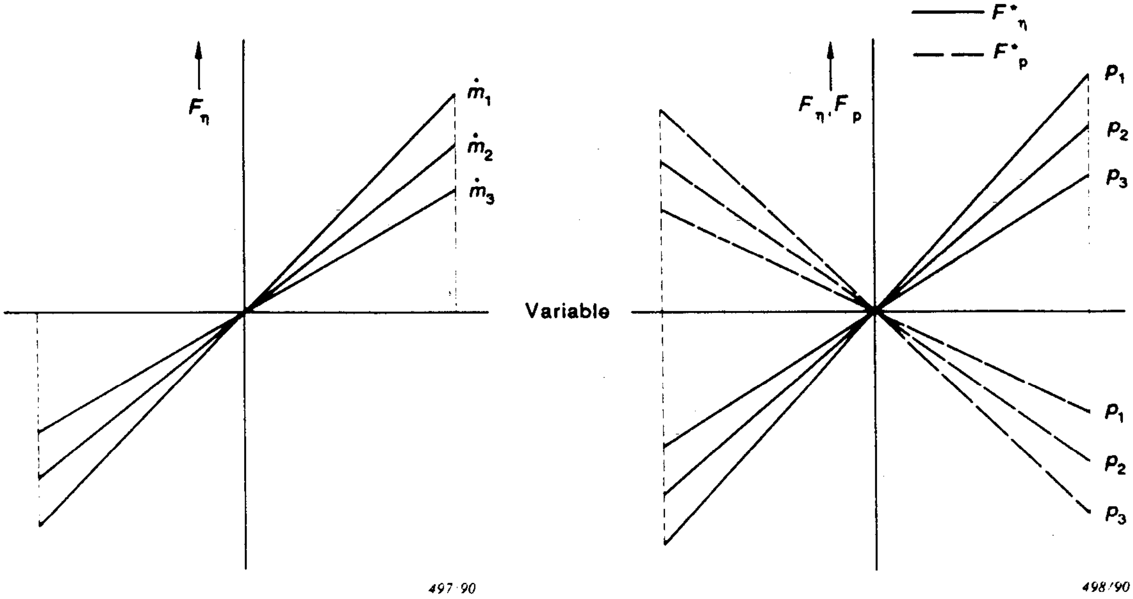


FIG. 13a. — Correction according to 6.6*a)*. FIG. 13b. — Correction according to 6.6*b)*.

FIG. 13. — Typical correction curves.

6.6.3 *Tests to determine correction values*

It is possible that the calculation of the correction factors referred to in 6.6.2 may not achieve a satisfactory standard of accuracy. In this event, and especially in relation to the exhaust pressure, it is recommended that special tests be carried out to determine the correction factors.

All tests of the same series in which one quantity is varied in a controlled way (e.g. the exhaust pressure by admitting air to the condenser) shall be run on the same day, by the same personnel and with the same apparatus. A sufficient interval of time shall be allowed between tests of the same series, for stable conditions to be established.

6.7 *Variables to be considered in the correction*

Corrections of the results may be made only for deviations from the guarantee conditions at the inlets to and/or outlets from the system, used as a basis for the definition of the guarantee, or for deviations inside this system, which are beyond the responsibility of the turbine supplier. For an individual case "system" can mean:

a) turbine only;

b) turbine and feed-water cycle with or without pumps;

c) turbine, feed-water cycle, condenser;

d) turbine, feed-water cycle, condenser and/or driven machine.

6.7.1 *Turbines with regenerative feed-water heating*

In the correction of test results of the thermal efficiency (or heat rate) of turbines with regenerative feed-water heating, deviations of the following variables or conditions from the guarantee conditions during the test have to be considered:

Category 1:

a) initial steam pressure[1],

b) initial steam temperature,

c) reheat steam temperature,

d) pressure drop in the reheater,

e) exhaust pressure or condenser cooling water inlet temperature and flow rate,

f) final feed-water temperature, if required[2],

g) speed.

Additional variables for turbines using wet steam:

h) initial steam quality,

i) steam quality at the outlet of the moisture separator[3],

j) terminal difference of reheater[3],

k) pressure drop in moisture separator and reheater[3]

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[1] Deviations of initial steam pressure from the specified value, resulting from a deviation of the steam flow capacity of variable pressure turbines from the specified value within the limits stipulated in the contract, shall be considered in the correction.

[2] Deviations of final feed-water temperature from the specified value, resulting from a deviation of the top heater terminal difference or steam extraction pipe pressure drop from the specified value within the limits stipulated in the contract, shall be considered in the correction.

[3] Only if this equipement does not form part of the scope of the contract.

Category 2:

a) Inlet temperature of condensate into feed-heating system (undercooling of condensate in condenser, influence of hydrogen cooler, oil cooler, ejector-steam condenser),

b) water flow for spray attemperation in the superheater and the reheater, unless this water is collected at the outlet of feed-heating system,

c) terminal difference of feed-heaters, condensate coolers and desuperheaters[2],

d) pressure drop in extraction lines[2],

e) enthalpy rise of feed-water in the feed-pump,

f) modifications of the configuration of the feed-heating system (e.g. total or partial by-pass of heaters),

g) make-up water,

h) level in feed-water reservoirs,

i) steam-ejector steam flow,

j) steam supply and steam inlet conditions of boiler feed-pump turbine.

k) any other heat additions or extractions (see also 6.4),

l) initial steam flow[4],

m) pressure drop in regulating valve(s) in throttling position[5],

n) any further deviations from guarantee conditions.

Category 3:

a) generator power factor,

b) voltage,

c) generator cooling gas pressure and purity.

6.8 *Guarantee comparison*

These rules do not include consideration of any arbitrary overall tolerances or margins on steam or heat consumption guarantees written in a contract. The test results shall be reported as calculated from the test observations, due account being taken of any corrections relating to the measurements.

The corrected test results shall be compared with the guarantee values specified in the contract.

The guarantee comparison shall be made in accordance with the correction method chosen (see 6.6).

When n guarantee points are given, the guarantee is considered fulfilled if:

$$\sum_{i=1}^{i=n} (\eta_{c,i} - \eta_{g,i}) \geqslant 0 \qquad (29)$$

unless otherwise stated in the contract.

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[4] A correction for differing initial steam flow is necessary only if correction and guarantee comparison are made to a guarantee point, not to a locus curve (see 6.8.1).

[5] The guarantee values are specified normally for valve points (see 3.6.1) and tests are conducted at valve points also with due consideration for the limits of deviations from guarantee conditions specified in Table I. A correction is not then necessary. If a throttle point is guaranteed (e.g. full arc admission turbine with throttle regulation at part load), the test shall be made with the throttling pressure drop specified in the guarantee conditions, or a correction has to be made.

If the different guarantee points are weighted in the contract, the weighting factors shall be applied appropriately in the guarantee comparison.

6.8.1 *Guarantee comparison with locus curve*

If several guarantee points with identical definitions (normally "valve points") are given, a locus curve of the guarantee values can be established.

If the test results have been corrected according to 6.6*a)* the locus curve shall be established as a function of initial steam flow $\dot{m}_1$ and the corrected test result η_c is compared with the value η_g of the guarantee curve at the measured initial steam flow $\dot{m}_{1,m}$ (see Figure 14a).

If the test results have been corrected according to 6.6.*b)* the locus curve shall be established as a function of output P and the corrected test result η_c is compared with the value η_g of the guarantee curve at the guaranteed output P_g (see Figure 14b).

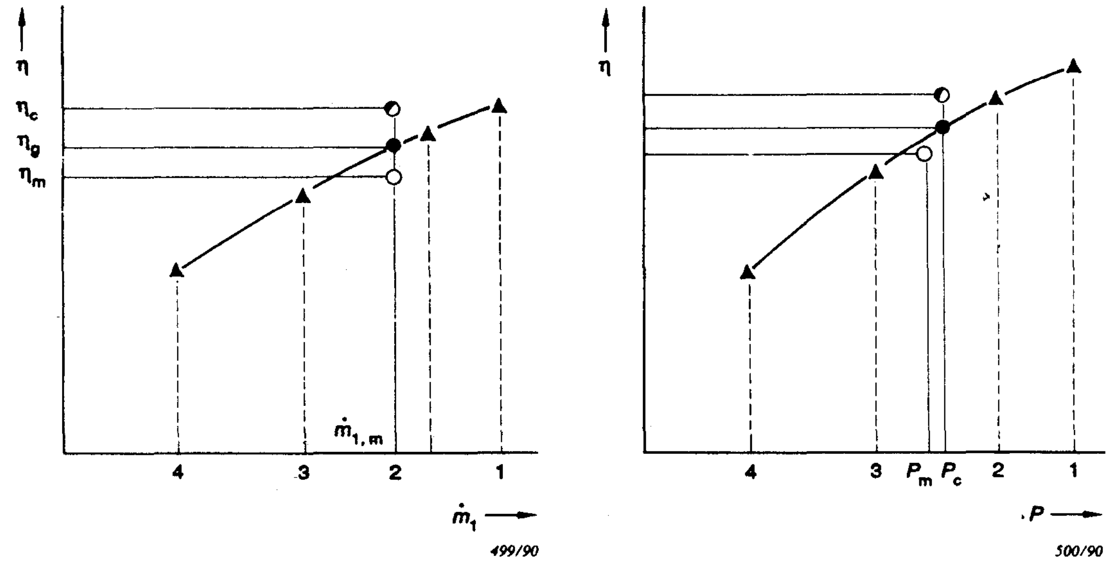


FIG. 14a. — Locus curve as function of initial steam flow.

FIG. 14b. — Locus curve as function of output.

▲ Guaranteed points
○ Measured points
◐ Corrected points
● Guaranteed locus point curve

FIG. 14. — Guarantee comparison on locus curve.

6.8.2 *Guarantee comparison with guarantee point*

For comparison with a single guarantee value, a test result corrected according to 6.6*a)* has to be corrected further for the influence of the difference between measured initial steam flow and guaranteed steam flow.

If the test result has been corrected according to 6.6*b)* only the difference between the corrected output and the guarantee output has to be considered for the further correction.

6.8.3 *Guarantee comparison for turbines with throttle regulation*

If, for turbines with throttle control, guarantees for partial loads are given, the amount of throttling in the control valves shall also be stated. The test result then has to be corrected also for the difference in throttling between guaranteed conditions and test conditions in a way which is in accordance with the method chosen in 6.6. Then the guaranteed comparison can be made according to 6.8.1 or 6.8.2.

Alternatively, the corrected test value can be compared with the value of the guaranteed locus curve at the same percentage value of initial steam flow capacity or corrected maximum output with valves wide open. The necessary value of the initial steam flow capacity or maximum output of the tested turbine can most conveniently be determined by a test run with valves wide open.

APPENDIX A

FEEDWATER HEATER LEAKAGE AND CONDENSER LEAKAGE TESTS
(see 3.4.5)

A1. Feedwater heater leakage tests

Heaters may be checked for leaks, with the turbine out of service, by using the condensate or boiler feed pumps to maintain pressure on the water side of the heaters. Leakage is indicated by the accumulation of water in the hot well or shell of the heater and, if normal operating water pressure is maintained, the rate of leakage may be estimated. It should be realized, however, that the rate of leakage may vary with the heater temperature. The measured rate of leakage should be regarded only as an indication of the relative tightness of the heater and should not be used as the basis for correction of the primary flow measurement.

In some installations, it may be possible to check for heater leakage with the turbine in service, if a tight shut-off of bled steam can be obtained and if there is no cascading of heater drains into the heater being checked.

If leakage is suspected, a useful method to check for heater leakage in actual service is to inject a small quantity of a water treatment chemical into the condensate line before the feed heater. A check of the conductivity of the heater drain condensate from any suspected heater will show, in the case of a leak, a sudden rise in conductivity as the chemical passes through.

A2. Condenser leakage tests

Prior to and directly after the turbine tests, a hydraulic test should be made on the condenser by filling the steam space with water up to at least 20 cm above the top row of tubes and noting the leakage of water, if any, into the water boxes at inlet and outlet.

An alternative method of condenser test before and after the turbine tests is to subject the condenser and turbine to full vacuum by closing off all access of air and steam and delivering normal water supply to the condenser tubes with the cooling water pumps. Weighed leakage into the hot well is a measure of condenser leakage. The tightness of the condenser, immediately before and during turbine tests, should be checked by an electrical conductivity test of a sample of the steam condensed from the exhaust of the turbine, a sample of condensate from the condenser's hot well and a sample of the cooling water after it has been diluted by a known amount of distilled water.

Alternatively, the leakage can be checked by a chemical method or by a fluorescence method.

APPENDIX B

THROAT TAP NOZZLE
(see 4.3.2.1)

B1. Design and manufacture

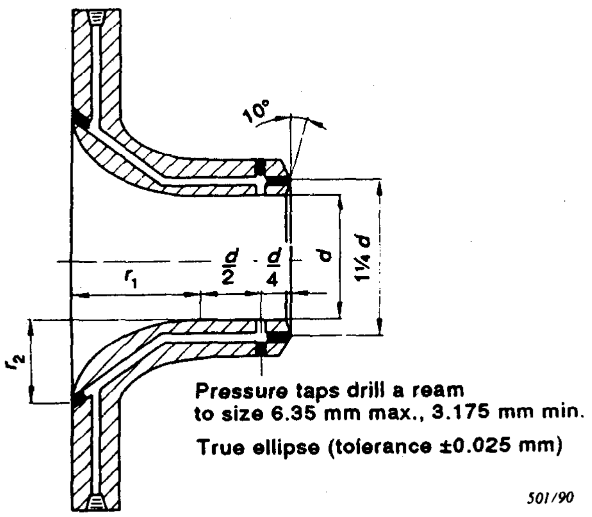
Because of the high degree of accuracy necessary, the following requirements are given regarding the design and manufacture of throat-tap nozzles for primary-flow measurement. Figure B1 is an example of a long-radius, low-ratio nozzle shape, with throat taps, that satisfies these requirements.

a) The entrance shall be designed to give a favourable pressure gradient so that the boundary layer will be very thin in the throat section and there will be no flow separations. Also, the entrance shall be designed to give a uniform flow approaching the throat section. The cylindrical section of the nozzle shall have parallel walls and be concentric with the pipe (see B2*b)*). Any divergence may cause a peculiarly shaped coefficient of discharge versus Reynolds number curve. However, slight convergence is acceptable, but no more than one thousandth mm per mm of throat length. The area in the plane of the throat taps shall be used in the coefficient calculation. Referring to Figure B1 the throat of the nozzle shall be round within the limits of ±0.0002 d, as determined by measurements on at least four diameters in the plane of the throat taps. The nozzle shall be made from a corrosion-resistant material with known thermal-expansion coefficient and its surface should have a $2 \cdot 10^{-4}$ mm finish or better, and shall be free from all burrs, scratches, imperfections, or ripples.

b) The pressure taps shall be at least two pressure-tap diameters deep. They shall be machined perpendicular to the bore surface, shall have sharp corners, and be free from burrs. The downstream pressure taps shall be machined in the throat of the nozzle in order to decrease the effect of downstream disturbances on this pressure measurement. The upstream taps shall be carefully made and shall be located one pipe diameter upstream from the nozzle entrance.

c) The final determination of the compliance with the above requirements is the shape of coefficient of discharge versus the Reynolds number curve (see Figure B2) which should be determined for each set of taps to be utilized. The nozzle shall be used only in the range where the throat Reynolds number exceeds $3 \cdot 10^6$.

d) In order to obtain maximum reading accuracy, the nozzle-throat diameter shall be selected to give the maximum deflection practicable, considering both the available pumping head and the manometer range. The manometer range should be selected to allow for fluctuations and for maximum flow which may be encountered. The nozzle shall not be used to measure flows which give manometer deflections of less than 1000 times the reading error, or 150 mm of mercury, whichever is larger. When it is necessary to measure flow over a larger range than can be obtained by complying with this requirement, it is permissible to use additional nozzles with different throat diameters. These nozzles shall be sized so that one of the test points can be measured with either nozzle.

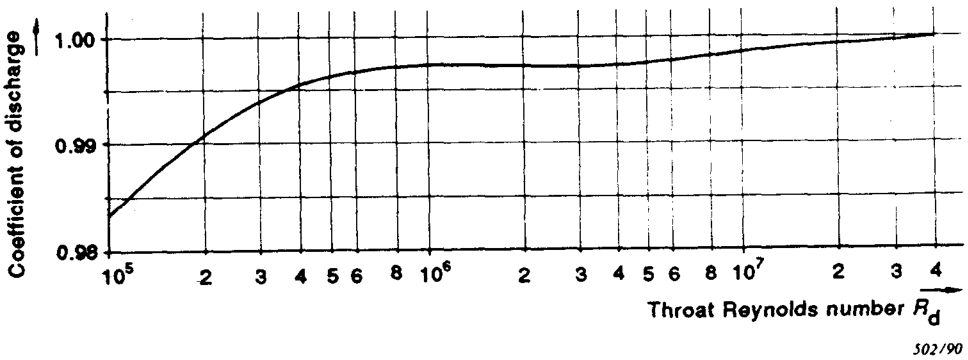

10°
$\frac{d}{2}$
$\frac{d}{4}$
d
$1\frac{1}{4}d$
r_1
r_2
Pressure taps drill a ream to size 6.35 mm max., 3.175 mm min.
True ellipse (tolerance ±0.025 mm)
501/90

Notes 1. — Pressure tap holes to have square and sharp corners and to be free of burrs. The pressure tap holes are to be drilled and reamed before the final boring and polishing of the throat. A plug with a press fit is then inserted in the hole. The final boring and polishing operation should be done after the insertion of the plug. The plug should be made with provision for pulling it out of the hole after the polishing and machining is completed. After removal of this plug, any slight burr which might be left on the edge of the hole may be removed by taking a tapered piece of maple and rolling it around the pressure tap.

2. — The throat of the nozzle may converge as much as 0.001 mm per mm. No divergence is acceptable.

3. — Material to be corrosion resistant.

FIG. B1. — Throat-tap flow nozzle.



Throat Reynolds No. × 10^{-6}	C
	$\beta = 0.43$
0.1	0.9834
0.2	0.9909
0.3	0.9939
0.4	0.9953
0.5	0.9961
0.6	0.9966
0.8	0.9970
1.0	0.9972
2.0	0.9970
3.0	0.9970
4.0	0.9972
5.0	0.9974
6.0	0.9978
8.0	0.9980
10.0	0.9983
20.0	0.9991
30.0	0.9994
40.0	0.9998

FIG. B2. — Typical nozzle calibration curve for $\beta = 0.43$.

For other values of β within the range 0.25–0.50:

$$C = C_{(\beta = 0.43)} + (0.011\,339\,\beta - 0.0049).$$

B2. Flow section

a) The flow nozzle shall be installed in a flow section as shown in Figure B3. This flow section shall contain either a flow straightener which divides the pipe cross-section into at least 50 approximately equal spaces, or a perforated multiplate flow straightener having approximately 200 holes per plate. There should be 20 diameters of straight run pipe upstream of the flow nozzle to ensure a sufficiently uniform velocity profile in the approaching stream. The requirement of at least 10 pipe diameters of straight pipe on the discharge side of the flow nozzle, of the same nominal size as the upstream pipe ensures a reliable throat-pressure measurement.

b) The flow nozzle shall be centred in the pipe within 0.8 mm of the pipe axis. The pipe on either side of the flow nozzle shall be smooth, free from rust, scale and blisters, and the inside diameter, measured at four points of any cross-section, shall not differ by more than 1 %. The upstream pipe section shall be bored as shown in Figure B4 for the entire length of the inlet section.

c) The pipe joint of the flow nozzle shall have the inner bores square with the faces of the flanges. The compressed thickness of the gaskets shall not exceed 1.6 mm and the gaskets shall not extend within the pipe.

d) In order to reduce the possibility of thermal distortion of the nozzle, it is desirable that the pipe and the flanges of the flow section be made of a corrosion-resistant material having the same coefficient of expansion as the nozzle.

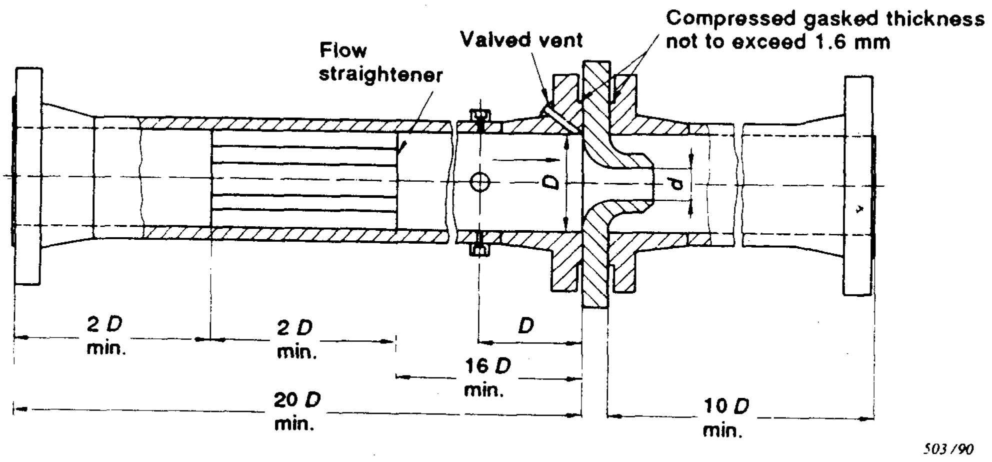


FIG. B3. — Flow section.

Note. — No obstruction, such as thermocouple, wells, backing rings, etc.

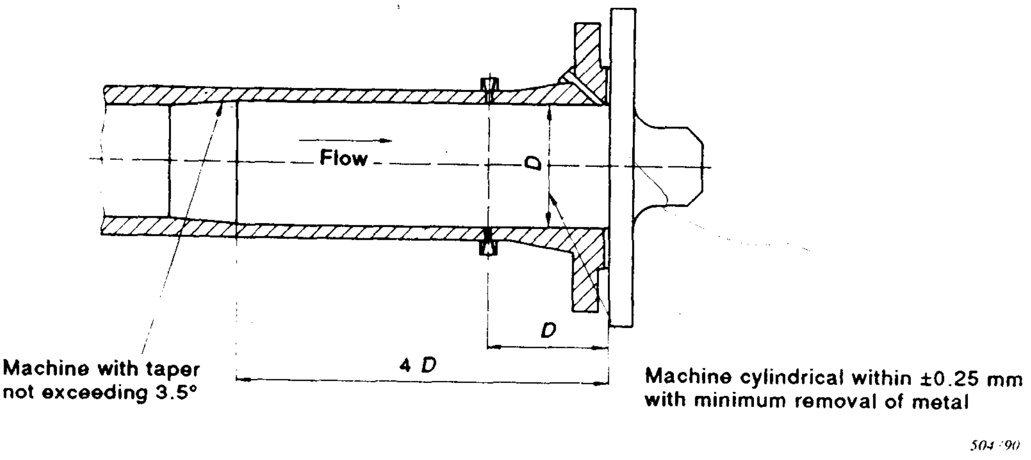

Flow
D
D
4 D
Machine with taper not exceeding 3.5°
Machine cylindrical within ±0.25 mm with minimum removal of metal
504/90

FIG. B4. — Boring in flow section upstream of nozzle.

B3. Calibration

a) Experience shows that the flow coefficient cannot be predicted within 0.1 % and, therefore, it is necessary to calibrate the flow sections (see Figure B3). This calibration shall be undertaken only by recognized authorities under conditions similar to those in the actual installation. It is desirable that the configuration of the piping in the calibrating set-up should be similar to that at the test site, immediately upstream and downstream of the flow-measuring section. Also, the Reynolds number, water temperature and other flow conditions should be as close to the test conditions as practicable. If the calibration of the flow section does not comply with B3*b)*, the nozzle shall be carefully inspected to conform to the requirement of B1*a)*, then corrected, if necessary and the flow section recalibrated. If the recalibration still does not comply with B3*b)*, the flow section should be calibrated using different facilities, if available.

b) Calibration shall be conducted on at least two sets of pressure taps 180° apart. For each set of taps, the calibration curve (not necessarily each individual point) shall be within 0.25% of the reference curve and shall have the same slope (see reference curve Figure B2). When it is not practicable to calibrate at the test Reynolds number, the calibration Reynolds number should be obtained in accordance with B3*c)*. The extrapolation to higher Reynolds numbers will then be parallel to the reference curve. The end point of the extrapolation shall not differ by more than 0.25% from the calibration curve coefficient at the highest Reynolds number attained during calibration.

The location of the primary flow section in the cycle, its configuration, and the technique which is employed to obtain the flow measurements are critical and are discussed in subsequent paragraphs.

c) Below a throat Reynolds number of $2 \cdot 10^6$ there is a transition from laminar to turbulent boundary layer. This transition region shall be established during calibration and shall be avoided during the test. It is permissible to extrapolate the calibration curve when the nozzle is used beyond the range of the calibrating facility, provided the level of the coefficient is established at Reynolds numbers higher than the transition region. This extrapolation should be parallel to the curve shown in Figure B2 and subject to the restrictions of B3*b)*.

d) It is preferable to install flow sections immediately before the test. A slight iron-oxide film on the nozzle surface will usually collect during the test. If this film is very thin (less than 0.025 mm and uniformly deposited) its effect on the accuracy of the flow measurement will be negligible. If the thickness of the deposit exceeds this value, or if the nature of the deposit is not-uniform and the surface appears rough, either of two procedures may be followed:

— the nozzle may be cleaned, reinstalled, and the test repeated; or

— the flow-measuring section may be recalibrated.

Care has to be taken not to disturb the deposit before recalibration. If this calibration is significantly different from the calibration prior to the test, it is necessary that another set of runs be made under deposit-free conditions. The test results cannot be adjusted, since it is usually impossible to determine when the deposit formed on the nozzle.

APPENDIX C

THE USE OF FLOW STRAIGHTENERS IN FLUID FLOW MEASUREMENTS

(see 4.3.3)

Flow straighteners in fluid flow measurement in closed pipes are used:

- to eliminate a swirl in the flow; and
- to flatten irregularities in the velocity profile of the flow.

Both will influence the flow measurement with a pressure difference device.

Irregularities in velocity profiles can also be eliminated by a sufficient length of straight pipe upstream of the meter. Elimination of a swirl in the flow, however, would require excessive lengths of straight pipe so that a straightener would be more economical.

Any flow straightener will also disturb the natural velocity profile to a certain extent unless it is of a special design as mentioned below. A combination of straightener with some straight pipe length upstream and downstream will therefore be the most effective.

Flow straighteners are of three different types:

a) A number of wire screens or perforated plates in series. A well-known straightener of this type is the straightener consisting of three perforated plates[1] placed at a pipe diameter distance from each other. It is designed primarily to eliminate irregularities in the velocity profile[2].

b) Multi-tube or multi-channel (rectangular) type. This type will be effective primarily to eliminate rotating components in the flow, but its effectiveness on velocity profile depends on the number of tubes or channels.

c) A combination of the types *a)* and *b)*. A well-known example of this type consists of a bundle of rectangular channels, preceded by a perforated plate with holes of sizes varying with the radius of the cross-section.

This straightener compensates for the disturbance in the velocity profile caused by a multiple tube type. The latter is, however, cheaper to manufacture.

The pressure loss in the type *a)* straightener is higher than that in the type *b)*.

As already indicated, the best effect will be obtained by providing some straight length of pipe upstream of the straightener[3].

Available data on application of straighteners in fluid flow measurement with pressure difference devices indicate that the following minimum distances could be recommended:

— straight length upstream of the straightener,	2 diameters
— length of straightener,	2 diameters
— straight pipe length between straightener and pressure difference device,	16 diameters

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[1] About 200 holes per plate.

[2] Also eliminates swirl.

[3] A sufficient length of straight pipe is required between the straightener and the pressure difference device to develop the required velocity distribution.

The choice of the type of straightener depends on the location of the flow measurement device in the piping system.

If the piping system has two bends in perpendicular planes upstream of the measuring section, a swirl may be produced in the flow. In this instance a straightener of the multiple tube type is recommended. The use of tube bundle flow straighteners may introduce errors if the flow section is preceded by a tee.